Edison Mission Energy

Greenhouse Gas Emission Factor Review

Final
Technical Memorandum

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1.0 INTRODUCTION

Global climate change is viewed as one of the most important issues of the 21st century. The momentum for responding is increasing as governments are adopting aggressive actions, including ratification of the Kyoto Protocol (expected in 2003) and establishing national, statewide, and regional emissions reporting initiatives or trading schemes. There is also increasing shareholder pressure on businesses in the developed world to demonstrate that they are taking responsibility to quantify and manage their greenhouse gas (GHG) emissions, particularly for carbon intensive industries.

Proactive companies are taking steps to identify not only the risks and challenges associated with the evolving climate change arena, but also the business opportunities that could be developed. To do this, however, companies must first have an understanding of the extent and nature of their greenhouse gas emissions.

In 2000, Edison Mission Energy (EME) began designing an internal Greenhouse Gas Tracking System or “Registry.” As part of this effort, EME participated as one of the original companies to road-test the “stationary combustion of fossil fuels” calculation tool being developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) as part of the GHG Protocol Initiative. EME has since integrated the original stationary combustion calculation tool into a Lotus-Notes database. An example of a typical fuel calculation is illustrated below:

Sample CO_2 calculation (HHV)

	A	B	C	D	E	F
GHG Model "Fuel Type"	GJ	Carbon emission factor (tC/TJ)	Carbon released (tC)	Oxidized carbon fraction	Carbon emissions (tC)	CO_2 emissions (tonnes)
	--	--	A*B/1000	--	C*D	E*3.644
Default - Coal (Sub-bituminous)	97,000,000	24.89	2,414,330	0.980	2,366,043	8,669,183
Default - Natural Gas (Dry)	93,000	13.77	1,281	0.995	1,274	4,669
Default = Oil (Gas/Diesel)	0	19.19	0	0.990	0	0
Total	97,093,000	--	2,415,611	--	2,367,318	8,673,852

1.1 Project Objectives

In 2002, EME contracted with URS Corporation to review GHG emission factors used by EME and provide comments on their adequacy, as well as guidance on potential improvements. In addition, EME requested a determination of “grid” emission factors to enable calculation of potential GHG emission reduction impacts associated with EME’s international renewable energy plants. This report presents findings and recommendations resulting from these activities.

The scope of work consists of two phases:

1. Data Analysis, presented in Section 2 – a technical review of EME's emission factors based on comparison to industry and internationally accepted emission factors ; and
2. Emission Factor Development, presented in Section 3 – establishing a calculation approach for estimating regional or national electric "grid" emission factors to compare against potential greenhouse gas benefits associated with international renewable energy projects.

The recommendations provided in this report are intended to further enhance EME's emission estimations, and to help ensure consistency and completeness in reporting.

1.2 Emission Factor Review Approach

The first phase of this project consisted of reviewing EME's emissions estimation documentation and supporting spreadsheets. Key findings from this review are documented in Section 2. The following files were provided by EME:

- "Carbon & CO2 Emission Factors.xls" – cites emission factors from IPCC, Table 1-1, Volume II (IPCC, 1996); distributed in the early development stages of the "Stationary Combustion of Fossil Fuels" calculation tool (WRI/WBCSD, 2001).
- "EME GHG Registry – Carbon Emission Factors.doc" – captures a screen from EME's Greenhouse Gas Tracking System showing default Carbon emission factors and Carbon oxidation factors for a variety of fuels.
- "CH4 & N2O Emission Factors for Utility Boilers.xls" – provides methane (CH_4) and nitrous oxide (N_2O) emission factors from IPCC Table 1-15, Volume III (IPCC, 1996) for different fuel and combustion technology combinations; distributed in the early development stages of the WRI/WBCSD Stationary Combustion Tool.
- "GHG Registry Methodologies.xls" – distributed in the early development stages of the "Stationary Combustion of Fossil Fuels" calculation tool (WRI/WBCSD, 2001).
- "EME GHG Registry.ppt" – a presentation file showing screen shots from EME's Greenhouse Gas Tracking System with annotation on how to use the program.
- "PlantSpecData Master rev3.xls" – a listing of all of EME's Energy Generation Units.

1.3 Emission Factor Development

The second project phase examined emissions associated with electricity generation in different countries where EME operates hydro-electric, geothermal and wind generation facilities. Two approaches (demonstrated through three methodologies) are presented for estimating national grid emission factors associated with a mix of electric generation types. One based on energy input, consistent with the unit convention of EME's Greenhouse Gas Tracking System; and the second based on MW-hr of electricity generation. The resulting emission factors can be used to evaluate the emissions benefit of renewable energy in different countries.

2.0 BENCHMARK OF EMISSION FACTORS

While there is no universally accepted international standard for estimating greenhouse gas emissions, two primary sources of data were used as a benchmark representing industry accepted practices against which to evaluate EME's emission factors:

1. American Petroleum Institute (API), Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, (API, 2001); and
2. World Resources Institute (WRI)/World Business Council for Sustainable Development (WBCSD), *The Greenhouse Gas Protocol* and associated Stationary Combustion Tool (WRI/WBCSD, 2001).

The API Compendium project reviewed numerous greenhouse gas protocols and methodology documents in an effort to compare and contrast different greenhouse emission estimation techniques and develop a document of internationally recognized best practices. Protocols from participating petroleum companies and publicly available guidance documents and inventory protocols were included in this detailed review. Internationally recognized sources reviewed under the API project include:

- EPA's AP-42 (EPA, 1995 including supplements A through F);
- Intergovernmental Panel on Climate Change (IPCC, 1996);
- Emission Inventory Improvement Program (EIIP, 1999);
- Energy Information Administration (EIA, 1996; EIA, 2001); and
- WRI/WBCSD (WRI/WBCSD, 2001).

API is currently reaching out to other protocol development organizations (governmental and non-governmental) to gain broad peer-review of its efforts, with the ultimate goal of achieving harmonization of estimation methods and improved global comparability of emission estimates. Although the focus of the Compendium is on oil and gas industry operations, methodologies presented for combustion sources and energy generation are directly applicable to electric utility operations. We believe that EME can benefit from lessons learned from the API developments in terms of identifying best practices for emission estimation.

The WRI/WBCSD GHG Protocol Initiative is an international undertaking to promote the use of standardized methods for estimating and reporting greenhouse gas emissions. Proposed principles and standards are provided for developing a corporate greenhouse gas inventory and for performance reporting. A separate spreadsheet tool is available for estimating emissions from stationary combustion sources and energy generation. The WRI/WBCSD GHG Protocol is widely cited and recognized as the accepted approach for developing greenhouse gas inventories.

Table 2-1 outlines the parameters and associated indicators used to evaluate EME's emission factors. Findings from the evaluation are provided in the following sub-sections.

Table 2-1. Emission Factor Review Parameters

Review Parameter	Key Indicators
Data Applicability	• Applicable to the conditions associated with the emission source • Consistency with recognized practices
Comprehensiveness and Data Quality	• Inclusion of all material sources • Accuracy of the emissions factors and estimation approaches for each material source • Consideration of factors that influence emissions
Transparency	• Identification of emission factor data sources with specific reference citations • Documentation of derivations and assumptions • Documentation to support consistent application of the emission estimation process

2.1 Data Applicability

Published emission factors represent an average emission rate from a typical emission source and, therefore, on average are applicable to other similar emission sources. However, emission rates may vary with equipment size, efficiency, and vintage, as well as maintenance and operational practices. This is particularly true of CH_4 and N_2O emissions, which can vary significantly because of factors that influence combustion efficiency. Applicability of an emission factor to a specific emission source requires an understanding of the conditions associated with developing the emission factor or a measurement of potential bias -- information that may not be readily available.

For this analysis, data applicability is assessed in terms of consistency by comparing EME's emission factors with other widely recognized sources of emission factors. Tables 2-2 through 2-4 benchmark EME's emission factors on a source by source basis for CO_2, CH_4, and N_2O, respectively. Findings from this comparison for CO_2 emissions are discussed separately from CH_4 and N_2O.

Tables 2-2 through 2-4 present emission factors in metric units (tonnes/TJ or grams/GJ). The US-based unit equivalent of these emission factors (lbs/million Btu) are presented in Appendix A.

Table 2-2. Comparison of CO_2 Emission Factors

All Emission Factors expressed as tonnes C/TJ (HHV)

Fuel Type	Original EME Default Value	Corrected EME Value	WRI/ WBCSD (IPCC-based factors)[1]	WRI/ WBCSD (DOE-based factors)[2]	API Compendium	% Difference (Corrected EME value versus Published factor)	
Alumina Smelter Waste	22.95	20.71	20.71			0%	EME vs. IPCC
Aviation Gasoline			17.92	17.92	17.90		
Biomass (Solid)	31.47	28.41	28.41			0%	EME vs. IPCC
Bitumen			20.90	20.96	20.96		
Blast Furnace Gas	73.33	59.40	59.40			0%	EME vs. IPCC
Chlorinated Solvents	21.58	19.48	19.47	19.47		0.01%	EME vs. DOE
Coal (Anthracite)	28.21	25.46	25.49	26.69	26.65	-4.59%	EME vs. DOE
Coal (Bituminous)	27.16	24.51	24.51	24.09	24.09	1.74%	EME vs. DOE
Coal (Fly Ash)	22.95	20.71	20.71			0%	EME vs. IPCC
Coal (Lignite)	29.05	26.22	26.22	25.28	25.25	3.74%	EME vs. DOE
Coal (Sub-bituminous)	27.16	24.51	24.89	24.96	24.91	-1.80%	EME vs. DOE
Coke (Oven Gas)	14.44	11.70	11.70			0%	EME vs. IPCC
Coke (Oven/Gas Coke)	31.05	28.03	28.03	28.03	28.07	0%	EME vs. DOE
Coke (Petroleum)	28.95	26.13	26.13	26.42	26.39	-1.11%	EME vs. DOE
Distillate Fuel			19.19	18.94	18.94		
Distillation Residues	22.95	20.71	20.72	20.72		-0.04%	EME vs. DOE
Ethane	17.68	15.12	15.96	15.44	15.45	-2.07%	EME vs. DOE
Fullers Earth	22.95	20.71	20.71			0%	EME vs. IPCC
Gasoline	19.89	17.96	17.96	18.36	18.42	-2.18%	EME vs. DOE
Kerosene (Jet)	20.53	18.53	18.34	18.34	18.70	1.02%	EME vs. DOE
Kerosene (Other)	20.63	18.62	18.53	18.72		-0.54%	EME vs. DOE
Liquid Wastes	22.95	20.71	20.72	20.72		-0.04%	EME vs. DOE
LPG	18.11	16.34	16.39	16.32	16.27	0.14%	EME vs. DOE

[1] The WRI/WBCSD Stationary Combustion tool provides a range of typical emission factors in different units. Emission factors provided on a lower heating value basis are taken from IPCC, Volume II Section 1, 1996.
[2] WRI/WBCSD emission factors provided on a higher heating value basis are taken from DOE, Appendix B, 2000.

Table 2-2. Continued

All Emission Factors expressed as tonnes C/TJ (HHV)

Fuel Type	Original EME Default Value	Corrected EME Value	WRI/ WBCSD (IPCC-based factors)[3]	WRI/ WBCSD (DOE-based factors)[4]	API Compendium	% Difference (Corrected EME value versus Published factor)	
Lubricants			19.00	19.00	19.20		
Natural Gas (Dry)	17	13.77	13.77	13.74	13.74	0.22%	EME vs. DOE
Natural Gas (Liquid)	18.11	16.34	16.34	16.35	16.35	-0.06%	EME vs. DOE
Oil (Crude)	21.05	19.00	19.00	19.22	19.22	-1.16%	EME vs. DOE
Oil (Gas/Diesel)	21.26	19.19	19.19	19.20	19.20	-0.03%	EME vs. DOE
Oil (Shale - Liquid)[5]	21.05	19.00	19.00	19.02	19.02	-0.08%	EME vs. DOE
Orimulsion	23.16	20.90	20.90			0%	EME vs. IPCC
Peat	30.42	27.46	27.46	27.45	27.42	0%	EME vs. DOE
Pitch	22.95	20.71	20.72	20.72		-0.04%	EME vs. DOE
Plastics	21.58	19.48	19.47	19.47		0.01%	EME vs. DOE
Refinery Gas	20.22	16.38	16.38	14.75	14.75	11.07%	EME vs. DOE
Residual Fuel Oil	22.21	20.05	20.04	20.41	20.39	-1.77%	EME vs. DOE
Saw Dust Impregnated	21.58	19.48	19.47	19.47		0.01%	EME vs. DOE
Sludges	22.95	20.71	20.72	20.72		-0.04%	EME vs. DOE
Solid Wastes	22.95	20.71	23.45	23.45		-11.69%	EME vs. DOE
Solvents	21.58	19.48	19.49	19.47		0.01%	EME vs. DOE
Synfuel	22.95	20.71	20.72	20.72		-0.04%	EME vs. DOE
Tar	22.95	20.71	20.72	20.72		-0.04%	EME vs. DOE
Tire Derived Fuel	24.42	22.04	22.24	22.24		-0.90%	EME vs. DOE
Waste Tires	24.42	22.04	22.04			0%	EME vs. IPCC
Wood/Wood Waste			26.04	26.04			

[3] The WRI/WBCSD Stationary Combustion tool provides a range of typical emission factors in different units. Emission factors provided on a lower heating value basis are taken from IPCC, Volume II Section 1, 1996.

[4] WRI/WBCSD emission factors provided on a higher heating value basis are taken from DOE, Appendix B, 2000.

[5] The early version of WRI/WBCSD included two emission factors for liquid shale oil. The first value is taken from IPCC, 1996, the second value cites data from Holderbank, 2000.

Table 2-3. Comparison of CH_4 Emission Factors

Fuel	Combustion Technology	Equipment Configuration	EME from IPCC Table 1-15, Volume 3 g CH_4/GJ (LHV)	EME from IPCC Table 1-15, Volume 3 Converted to g CH_4/ GJ (HHV)	AP-42 Converted to g CH_4/ GJ (HHV)	AP-42 Reference Table, Year, and Quality Rating	% Difference (AP-42 vs. IPCC)
Coal	Pulverized Bituminous Combustion	Dry Bottom, wall fired	0.7	0.665	0.662	Table 1.1-19, 9/98, B	0.5%
		Dry Bottom, tangentially fired	0.7	0.665	0.662		0.5%
		Wet Bottom	0.9	0.855	0.827		3.3%
	Bituminous Spreader Stokers	With and without re-injection	1	0.95	0.993		-4.3%
	Bituminous Fluidized Bed Combustor	Circulating Bed	1	0.95	0.993		-4.3%
		Bubbling Bed	1	0.95	0.993		-4.3%
	Bituminous Cyclone Furnace		0.2	0.19	0.165		14.8%
Oil	Residual Fuel Oil/Shale Oil	Normal Firing	0.9	0.855	0.803	Table 1.3-3, 9/98, A	6.5%
		Tangential Firing	0.9				
	Distillate Fuel Oil	Normal Firing	0.9	0.855	0.861		-0.6%
		Tangential Firing	0.9				
	Large Diesel Fuel Engines >447 kW		4	3.8	3.485	Table 3.4-1, 10/96, E	9.0%
Natural Gas	Boilers		0.1	0.090	0.97	Table 1.4-2, 7/98, B	90.7%
	Large Gas-Fired Gas Turbines >3MW		6	5.4	3.7	Table 3.1-2a, 4/00, C	45.9%
	Large Dual-Fired Engines		240	216	258.2	Table 3.4-1, 10/96, E	16.3%

Table 2-4 Comparison of N_2O Emission Factors

Fuel	Combustion Technology	Equipment Configuration	EME from IPCC Table 1-15, Volume 3 g N_2O/GJ (LHV)	EME and IPCC Converted to g N_2O/ GJ (HHV)	AP-42 Converted to g N_2O/ GJ (HHV)	AP-42 Reference Table, Year, and Quality Rating	% Difference (AP-42 vs. IPCC)
Coal	Pulverized Bituminous Combustion	Dry Bottom, wall fired	1.6	1.5	0.5	Table 1.1-19, 9/98, E	206.2%
		Dry Bottom, tangentially fired	0.5	0.5	1.3		64.1%
		Wet Bottom	1.6	1.5	1.3		14.8%
	Bituminous Spreader Stokers	With and without re-injection	1.6	1.5	0.7		129.7%
	Bituminous Fluidized Bed Combustor	Circulating Bed	96	91.2	57.9	Table 1.1-19, 9/98, B	57.5%
		Bubbling Bed	96	91.2	57.9		57.5%
	Bituminous Cyclone Furnace		1.6	1.5	1.5	Table 1.1-19, 9/98, E	2.1%
	Lignite Atmospheric Fluidized Bed		42	39.9	41.4	Table 1.7-4, 9/98, E	-3.6%
Oil	Residual Fuel Oil/Shale Oil	Normal Firing/ Tangential Firing	0.3	0.3	0.3	Table 1.3-3, 9/98, B	-9.7%
	Distillate Fuel Oil	Normal Firing/ Tangential Firing	0.4	0.4	0.3	Table 1.3-3, 9/98, B	12.4%
Natural Gas	Boilers		NAV		0.9	Table 1.4-2, 7/98, E	
	Large Gas-Fired Gas Turbines >3MW		NAV		1.3	Table 3.1-2a, 4/00, E	

NAV is not defined by IPCC.

2.1.1 Evaluation of CO_2 Combustion Emission Factors

Table 2-2 compares CO_2 emission factors from EME, WRI/WBCSD, and the API Compendium. For this comparison, all of the published emission factor values are converted to the same unit basis: tonne C/TJ on a higher heating value (HHV) basis. The table also calculates the percent difference between the "corrected" EME value and the published source indicated in far right-hand column.

The EME emission factors, reported in tonnes of carbon per TJ (LHV basis) are taken from an early version of WRI/WBCSD's stationary combustion tool. EME added an additional column to convert the emission factors from a LHV basis to a HHV basis. The conversion between LHV and HHV originates from IPCC, which states that their emission factors were originally based on gross (or higher) heating value but converted to net (or lower) heating value by assuming LHV is 5% lower than HHV for coal and oil and 10% lower for natural gas (IPCC, Table 1-4, 1996). An error results, however, in applying this conversion to emission factors (expressed in units of mass of emissions per fuel energy input) rather than heating values (expressed in units of fuel mass or volume per energy input). Derivation for the correct emission factor (EF) conversion is provided in Appendix B.

This conversion issue accounts for 10% of the difference between the "original" EME value and other published factors for liquid and solid fuels and 20% of the difference for gas fuels. The "corrected" EME factors, using the correct LHV to HHV conversion, are similar to the IPCC-based WRI/WBCSD factors.

Other, smaller, differences between the CO_2 emission factors shown in Table 2-2 are believed to be a result of different fuel properties. Where the IPCC-based data likely consist of a mix of fuels internationally, the DOE-based emission factors rely on U.S. fuel properties. Because the majority of EME operations are within the U.S., U.S.-based emission factors are recommended over the IPCC-based factors. The API Compendium cites EPA and DOE published emission factors (EIIP, 1999; and EIA, 2000) for the majority of the carbon or CO_2 emission factors and provides clear references to the root data sources. Where the API Compendium does not address a specific fuel type used by EME, the DOE-based emission factors referenced by WRI/WBCSD are recommended. In addition, to ensure transparency, EME should document the source of each emission factor value.

Please note, as discussed in the evaluation of data quality (Section 2.2), average emission factors such as shown in Table 2-2 are not the preferred approach. Emission estimates developed from fuel-specific data are more reliable than published average emission factors and are recommended over the use of average emission factors.

2.1.2 Evaluation of CH_4 and N_2O Combustion Emission Factors

Tables 2-3 and 2-4 compare EME's CH_4 and N_2O emission factors for combustion sources to factors published in AP-42 (EPA, 1995, with Supplements through 2000). The key difference between these emission factors sources stems from the vintage of the data. EME emission factors are taken from IPCC (IPCC, 1996) which references the 5th Edition of AP-42 (published in 1995). AP-42 is routinely updated to include new test data in an effort to improve the quality of emissions factors. Since the 5th edition was published, six supplements have been published, three of which have made revisions to CH_4 or N_2O emission factors from combustion sources. The columns showing percent difference in Tables 2-3 and 2-4 indicate the relative change in the emission factors since 1995 and show that some of the emission factors have changed significantly. For CH_4 and N_2O combustion emission estimates, the AP-42 factors are recommended as the preferred approach.

2.2 Comprehensiveness and Data Quality

Comprehensiveness is evaluated in terms of the completeness of EME's inventory with respect to the sources included and consideration of the conditions that contribute to emissions. The quality of the emission factors is also examined in this section.

Ideally, all emission sources within EME's operational and organizational boundaries should be included in the inventory. In practice though, the cost to collect the necessary information for small sources may be prohibitive. Consideration of materiality or de minimus thresholds is needed to support the goals of the EME inventory process without overburdening the reporting entities.

Materiality of a source can only be established after it has been assessed. However, this assessment can be based on an approximation of the emission rate using available data. The key requirement is documented justification of the decision to exclude a particular source and assurance that this exclusion does not significantly impact the reported GHG data.

2.2.1 Combustion Emission Sources

For CO_2, a listing of carbon-based emission factors and oxidation values for different fuel types is provided in the file "EME GHG Registry – Carbon Emission Factors.doc". This listing appears complete with respect to the fuel types considered in comparison to other protocol documents (refer to Table 2-2), and could perhaps be simplified somewhat by eliminating fuel types not relevant to EME's operations.

EME's carbon oxidation values are consistent with IPCC's recommended values of 0.98 for coal, 0.99 for oil and oil products, 0.995 for gas, and 0.99 for peat used in electricity generation (IPCC, 1996). For coal, the US Environmental Protection Agency (EPA) recommends a value of 0.99 because coal combustors in the U.S. achieve more complete combustion than the global average reflected in the IPCC value (EIIP, Volume VIII, 1999). The API Compendium applies a conservatively high approach by assuming 100% conversion of all fuel carbon to CO_2, thus double counting the carbon that is released as uncombusted CH_4 (API, Section 4.1, 2001)[6]. This is also the approach used by the WRI/WBCSD GHG Protocol (WRI/WBCSD, 2001). Ultimately, when applying the carbon oxidation factor to an average fuel emission factor, the minor difference between 98% and 99% carbon efficiency is small compared to the assumptions associated with the average factor.

The file “CH4 & N2O Emission Factors for Utility Boilers.xls” provides emission factors based on fuel type, combustion technology, and equipment configuration (refer to Tables 2-3 and 2-4). These classifications are consistent with the factors that influence CH_4 and N_2O combustion emissions.

Ideally, data quality is assessed through statistical analysis of accuracy and precision. AP-42 provides quality ratings for each of their emission factors. These are shown in Tables 2-3 and 2-4 for the CH_4 and N_2O emission sources. A rating of “A” represents excellent quality data, meaning the factor is based on a large data set with a random pool of facilities in the population. Rating “B” represents above average quality, while “C” is average. A rating of “D” represents a factor with below average quality, mainly resulting from limited data points or not having a random sample of the industry. A rating of “E” represents a poor quality factor, with a high degree of variability within the source category population. Most of the CH_4 emission factors have an above average quality rating, while the quality rating is poor for the majority of the N_2O emission factors.

Early studies (prior to 1988) reported substantial levels of N_2O emissions from fossil fuel-fired systems, with levels proportional to NO_x emissions. This is perhaps the basis for the approach used in Canada for estimating N_2O emissions as 1.5% of NOx emissions (CAPP, 2000).

However, it was later determined that the high levels of N_2O measured were an artifact of the sampling procedure. More recent measurement programs utilize alternate sampling techniques and have measured much lower N_2O emission rates. Current AP-42 emission factors reflect these more recent results, but the number of measurements is rather limited. The API Greenhouse Gas Emissions Workgroup, which developed the API Compendium, will begin a study of N_2O emission factors for stationary combustion sources in early 2003. This study will compile additional N_2O emission measurements from an earlier API program, review literature for more recent studies, and gather data from participating petroleum companies. The information will be evaluated to assess the quality and applicability of the emissions factors and to determine the relative contribution of N_2O emissions for different facility types. Results from this study will provide justification for or disprove the common assumption that N_2O emissions are negligible. EME’s Greenhouse Gas Tracking System should incorporate results from the API N_2O study, when available.

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[6] The application of oxidation factors is currently being revisited by the API GHG Emissions Workgroup for possible inclusion in the next version of the API Compendium.

An assessment of emission factor quality or access to information from which to analyze emission factor quality is generally not available from published sources, as is the case for the CO_2 data shown in Table 2-2. For these emission factors, the evaluation relies on a qualitative assessment of quality and appropriateness.

Ultimately, the accuracy of greenhouse gas emission estimates should be consistent with the intended use of the information. Figure 1 illustrates the hierarchy associated with a range of emission estimation options (API, 2001). For an overall assessment of emissions, published emission factors are generally acceptable. Regulatory reporting or emissions trading programs may require higher levels of assurance based on source-specific measurements or monitoring.

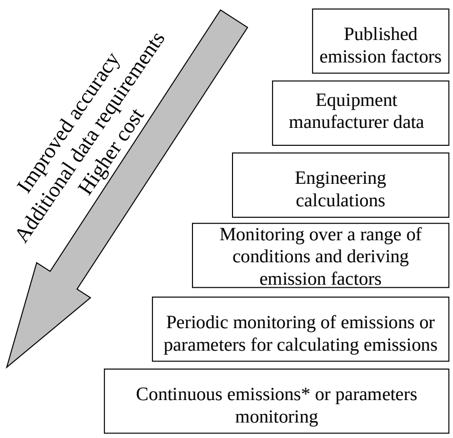

Figure 1. Hierarchy of Estimation Approaches

* Note, continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for greenhouse gas emissions (API, 2001).

Carbon dioxide emissions from combustion sources are the single largest contributor to EME's GHG emissions inventory. Therefore, the accuracy of EME's emission estimates is highly dependent on the accuracy of the CO_2 emission estimates.

Figure 2 provides a decision tree adapted from the API Compendium (API, 2001) that prioritizes the estimation techniques for CO_2 emissions from combustion sources. The preferred approach relies on measured fuel consumption rates and fuel carbon content. With this information, CO_2 emissions can be accurately estimated from a material balance. The material balance can conservatively assume all of the carbon in the fuel forms CO_2 (i.e., complete combustion, which is the approach recommended by WRI/WBCSD and adopted by the API Compendium), or apply measured or default combustion efficiencies (referred to as OCF values in the EME GHG Tracking System). Appendix C provides further details on estimating CO_2 emissions based on fuel analysis.

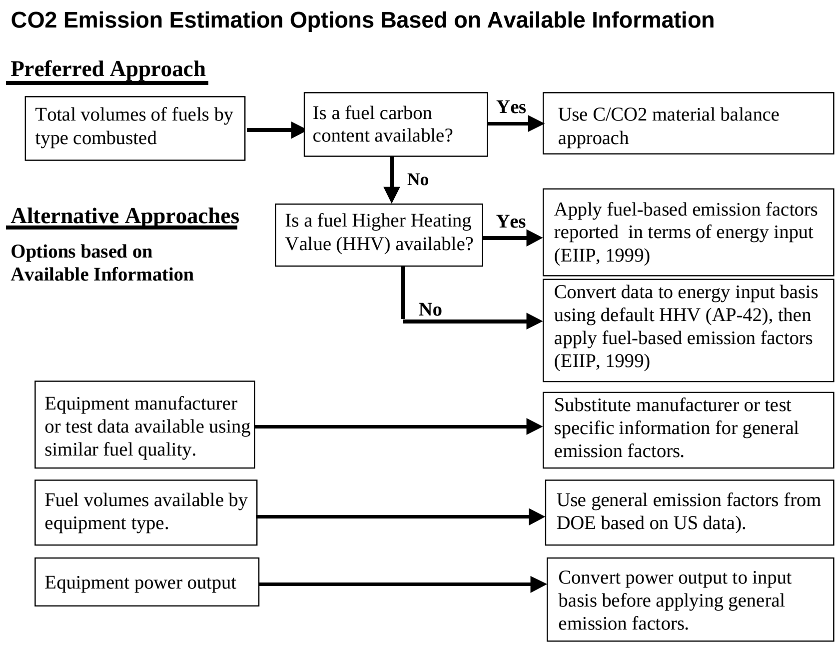

Figure 2. CO_2 Emission Estimation Techniques

For combustion sources subject to the Acid Rain Rule (40 CFR Part 75), CO_2 emissions in the flue gas may be available from a continuous emissions monitoring system (CEMS). However, the accuracy of the CEM measurements can be lower than an estimate of CO_2 emissions based on fuel consumption and composition. In the absence of fuel composition and consumption rate, CEM data, if available, is preferred over average emission factors.

2.2.2 Non-combustion Emission Sources

Non combustion emission sources include vented releases due to maintenance or emergency activities, as well as fugitive emissions (i.e., unintentional leaks emitted from sealed surfaces or pressurized equipment). For EME's operations, these sources might include:

- CH_4 emissions from equipment associated with supplying natural gas for electric generation, such as compressors, control devices and distribution pipelines;
- Cooling towers or anaerobic wastewater treatment; and
- SF_6 used to insulate transmission lines (the GHG Tracking System does provide an option for assessing SF_6 emissions).

Although emissions from these sources are expected to be small relative to combustion sources, from a boundary consideration perspective, EME should determine whether these types of sources are applicable to its operating facilities. Techniques for estimating non-combustion CH_4 emissions are available in the API Compendium. A summary of potentially applicable emission factors is provided in Appendix D.

2.2.3 Exported Energy

Electricity or steam derived from fuel combustion will produce CO_2, CH_4, and N_2O emissions. For the generator, these are direct emissions resulting from fuel combustion. EME's GHG Tracking System is focused on quantifying these emissions based on fuel consumption. Electricity sales (in MW-hrs) and steam sales (in MMBtu) are tracked within the system to characterize a unit's emission rate and thermal efficiency. These values are not used to adjust the emission estimates. This is consistent with WRI/WBCSD guidance to not deduct emissions associated with exported energy, but to track it separately in supplemental information.

For EME's customers that track GHG emissions or participate in various registry or reporting programs, energy purchased from EME would be accounted for as part of their indirect emissions. EME could offer generation specific emission factors as a service to these customers. For cogeneration where steam and electricity are provided to different customers, the WRI/WBCSD stationary combustion tool provides an approach for allocating fuel combustion emissions between steam and electricity generation based on the work potential of the two streams (WRI, 2001). This approach essentially partitions the total emissions that result from fuel combustion between the two energy streams. The WRI/WBCSD allocation approach is discussed further and illustrated in Appendix E.

2.2.4 Imported Energy

Emissions related to purchased or imported energy from outside EME's organizational boundary are typically defined as "indirect" emissions (WRI/WBCSD Scope 2). The generation of such energy results in emissions from sources outside EME's control, but can be attributable to EME's business activities. Although EME is a generator of electricity and steam, there may be some operations or situations that would require EME to purchase energy from an outside source (e.g., corporate offices). Including these indirect emissions in EME's overall carbon footprint would enable EME to characterize the benefits of energy conservation/efficiency improvement activities. EME may want to consider quantifying the indirect emissions associated with these activities and accounting for these sources in the GHG inventory. This approach would be considered a best practice and is consistent with WRI/WBCSD guidance that companies should, at a minimum, account and report GHG emissions from Scope 1 (direct sources) and Scope 2 (indirect sources).

2.3 Transparency

Information describing the source and use of emissions data for EME's GHG Tracking System was provided in the file "EME GHG Registry.ppt" and through correspondence between URS and EME.

As EME's greenhouse gas emission estimation evolves and expands to participate in trading or outside registry initiatives, transparency will become essential. Transparency relates to the degree in which the GHG emissions data are determined to be reliable (WRI, 2001), and ultimately, the reliability of the reported GHG data depends on the quality of the data trail from the emission source. Data collectors and estimators should be able to demonstrate through records and documentation how information is derived, what assumptions are used, and why the methods chosen are reasonable.

A formal protocol should support the inventory by addressing roles and responsibilities, data management processes, and emission inventory objectives. Other types of documentation that should be maintained with EME's inventory include:

- Organizational and operational boundaries and the approach used to allocate emissions where facilities or operations are not owned or operated solely by EME;
- Emission sources included or excluded from the inventory;
- Detailed reference information for each emission factor, including publication date;
- Conversion factors and details on the derivation of emission estimation approaches;
- Source of activity related information used in estimating emissions (e.g., fuel analysis and consumption records);
- Exceptions and assumptions; and
- Corrections made to previous estimates.

Another aspect of transparency is the evidence of consistency in terms of estimation approaches, emission sources, and presentation of data. Consistency over time is necessary to identify trends and assess progress.

As with transparency, consistency also requires detailed documentation. Any changes to the process of estimating emissions or the basis of reporting should be clearly documented to enable comparison among past, present, and future data. A formal inventory protocol also supports consistency over time, in the event of personnel changes or as EME's greenhouse gas program evolves.

3.0 International Grid Emission Factors

Renewable energy is a key component in reducing global greenhouse gas emissions. EME has made significant strides in developing renewable energy sources through the initiatives summarized in Table 3-1. This section describes a methodology for examining potential GHG benefits associated with these operations, compared to average electric "grid" emissions for the regions where these facilities are located. Additional details on the derivation of these emission factors are provided in Appendix F.

Table 3-1. EME Renewable Energy Facilities

Facility	Location	Generation Technology	Generation Capacity
IVPC4	Italy	Wind	156 MW
Clyde	Clyde, New Zealand	Hydro	432 MW
Ohaaki	Ohaaki, New Zealand	Geothermal	104 MW
Poihipi	Central North Island, New Zealand	Geothermal	55 MW
Roxbourgh	Roxbourgh. New Zealand	Geothermal	320 MW
Wairakei	Wairakei, New Zealand	Geothermal	165 MW
CBK	Laguna Province, Luzor Philippines	Hydro	728 MW
Spanish Hydro	18 locations in Spain	Hydro	86 MW
Dinorwig	North Wales, UK	Hydro	1,728 MW
Ffestiniog	Wales, UK	Hydro	360 MW

3.1 Grid Emission Factor Development

GHG benefits should be assessed against other sources of electricity that serve the same distribution area. In the absence of local grid data associated with the facilities of interest, the International Energy Administration (IEA)[7] provides a reputable and consistent source of country-based information. A summary of electric generation information for Italy, Spain, New Zealand, UK, Australia, and the Philippines is provided in Appendix F.

GHG emissions associated with a region's electric grid can be estimated based on the MW-hr of electricity generated or based on the heat input associated with the generated electricity. Heat input based on fuel combustion is appropriate for onsite electricity generation, where the quantity and heat rate of the fuels consumed are known. Heat input data are less likely to be available for

[7] The IEA is an autonomous body within the Organization for Economic Co-operations and Development (EOCD) and contributes data to support the International Panel on Climate Change (IPCC) methodologies for estimating greenhouse gas emissions.

electricity generated offsite. In addition, renewable energy such as wind and hydroelectric, produce electricity with no corresponding production of heat.

EME requested electric "grid" emission factors in terms of heat input, to be consistent with the unit convention used by their GHG Tracking System. Our recommendation is to use electric generation based emission factors. As a compromise, electric grid emission factors were developed based on root emission factors for electric generation, but converted to a heat input basis using heating values developed for each country. Details of these calculations are presented in Appendix F. Tables 3-3 and 3-4 present the resulting emission factors in two sets of units (TJ/GJ and MW-hr, respectively). Table 3-3 also provides the heat rate factors necessary to convert between the two unit sets.

Table 3-3. Average Country Heat Rates and "Grid" Emission Factors for 2000

Generation Derived Heat Input Values

		Emission Factors			
Country	**Heat Rate, BTU/kW-hr**	**CO_2 Tonnes/TJ**	**C Tonnes/TJ**	**CH_4 g/GJ**	**N_2O g/GJ**
Australia	8,901	80.07	21.84	1.637	13.26
Italy/Sicily	7,409	60.22	16.42	0.643	3.832
New Zealand	4,186	36.49	9.952	0.723	4.174
Philippines	10,631	44.05	12.01	0.612	5.061
Spain	4,953	81.93	22.34	1.484	11.68
UK	6,154	73.24	19.97	1.429	10.05
US	7,598	69.78	19.03	1.420	11.17

Table 3-4. Average National "Grid" Emission Factors for 2000

Electricity Generation Approach

	Tonnes/MW-hr			
Country	**CO_2**	**C**	**CH_4**	**N_2O**
Australia	0.751	0.2045	1.54E-05	1.24E-04
Italy/Sicily	0.470	0.128	5.02E-06	2.99E-05
New Zealand	0.161	0.044	3.19E-06	1.84E-05
Philippines	0.494	0.135	6.86E-06	5.67E-05
Spain	0.428	0.117	7.75E-06	6.11E-05
UK	0.475	0.130	9.27E-06	6.52E-05
US	0.559	0.152	1.14E-05	8.95E-05

3.2 Assessing Benefits

Currently, an approach for determining the greenhouse gas benefits of renewable energy compared to other electricity generation methods has not been published by the various protocol development organizations. It is likely that this topic will be addressed in future revisions of the WRI/WBCSD GHG Protocol or the DOE 1605(b) Registry. In the absence of a standard method, it would be logical to estimate the reduction in GHG emissions associated with EME's renewable projects by comparing the total emissions resulting from an EME facility to the emissions that would result from an equivalent TJ or MW-hr production using the national average grid factors. For example, every TJ or MW-hr of hydro-electric generation from the Dinorwig facility is assumed to result in zero GHG emissions[8]. Using the UK emission factors presented in Table 3-4, the greenhouse gas benefit of this facility is calculated as shown:

$$\frac{80.07\ \text{tonnes}\ CO_2}{TJ} + \left(\frac{1.637\ \text{g}\ CH_4}{GJ} \times \frac{10^3\ GJ/TJ}{10^6\ \text{g/tonne}} \times \frac{21\ \text{tonnes}\ CO_2\ Eq.}{\text{tonne}\ CH_4}\right) +$$

$$\left(\frac{13.26\ \text{g}\ N_2O}{GJ} \times \frac{10^3\ GJ/TJ}{10^6\ \text{g/tonne}} \times \frac{310\ \text{tonnes}\ CO_2\ Eq.}{\text{tonne}\ N_2O}\right) = 84.22\ \text{tonnes}\ CO_2\ Eq./TJ$$

Resulting CO_2 equivalent (CO_2 Eq.) emission factors for the other countries are provided in Table 3-5.

Table 3-5. CO_2 Equivalent "Grid" Emission Factors for 2000

Country	CO_2 (Tonnes C/TJ)	CH_4 (g/GJ)	N_2O (g/GJ)	CO_2 Eq. (Tonnes C/TJ)[a]
Australia	80.07	1.637	13.26	84.22
Italy/Sicily	60.22	0.643	3.832	61.42
New Zealand	36.49	0.723	4.174	37.80
Philippines	44.05	0.612	5.061	45.63
Spain	81.93	1.484	11.68	85.58
UK	73.24	1.429	10.05	76.39

[a] CO_2 equivalent emissions are based on global warming potentials of 21 for CH_4 and 310 for N_2O.

[8] Note, this assumption would need to be verified based on facility information. For example, GHG emissions may result due to the use of SF_6 or from supplemental electricity generation by fuel combustion during dry spells.

4.0 CONCLUSIONS AND RECOMMENDATIONS

EME has made significant progress in developing greenhouse gas emission estimates through the EME GHG Tracking System. A data management system, such as this, provides a consistent method of estimation and increases the reliability of data. A review of the emission factors used by the GHG Tracking System is the primary purpose of this document. Conclusions and recommendations are presented in this section.

Review of the emission factor information provided by EME revealed an error in the conversion of fuel-based CO_2 emission factors from a LHV basis to a HHV basis. Correcting this error will result in CO_2 emission factors comparable to other published sources. However, the overall accuracy of EME's emission estimates would benefit most from revising the estimation approach to use fuel consumption and composition data rather than general emission factors. Should EME choose to implement the more detailed calculation approach using fuel composition data, the carbon oxidation values for coal should be re-examined to ensure consistency with U.S. guidance.

The contribution of CH_4 and N_2O emissions to EME's overall greenhouse gas inventory is low relative to CO_2. As a result, default emission factors are generally appropriate for quantification of CH_4 and N_2O emissions from combustion sources. A comparison of the CH_4 and N_2O emission factors included in the EME GHG Tracking System to other published sources indicated that the EME factors are not consistent with current data sources. Updating these emission factors to the most current AP-42 emission factors (provided in Tables 2-3 and 2-4) is recommended. In addition, documenting the table number and publication date associated with the AP-42 emission factors, since they change frequently, will provide transparency and simplify future updates to the Tracking System. We also recommend incorporating results from API's study on N_2O emissions from combustion sources, when available.

The following are additional recommendations to further enhance EME's greenhouse gas inventory initiatives.

Data Applicability

- Establish a system for updating emission factors as part of a periodic protocol revision process, such as an annual review of AP-42 for revised emission factors.
- Incorporate new data resulting from the upcoming API study on N_2O emission factors.
- Document the heating value convention when energy (TJ) values are reported to avoid mixing lower and higher heating values.

Comprehensiveness and Data Quality

- Include emission factors or estimation approaches to quantify CH_4 emissions from natural gas equipment, if EME's operations include these sources.

- Include emission factors or estimation approaches to quantify emissions from cooling towers or anaerobic wastewater treatment if EME's operations include these sources.
- Include SF_6 emission estimates as part of EME's overall greenhouse gas inventory.

Transparency

- Include complete emission factor references for those factors taken from other published sources.
- Include supporting documentation for internally derived emission factors in protocol to ensure transparency.
- Document background data and assumptions associated with emission factors and estimation approaches.
- Summarize methodological revisions or corrections from previous year's estimates and the impact of these changes on emissions from particular sources.

Average electric "grid" emission factors were developed to assist EME in evaluating emission benefits associated with renewable energy projects. These emission factors are provided in terms of heat input for consistency with the unit convention currently used by EME's GHG Tracking System. Ultimately however, we recommend adopting emission factors based on electricity generation. We believe this approach is more applicable to renewable energy sources, where electricity is generated without producing significant heat. In addition, electricity output is more readily available for electricity produced by other generators and consistent with electricity emission factors developed or reported by other organizations.

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Appendix A: Emission Factors (lbs/MMBTU)

The following tables provide a comparison of emission factors similar to Tables 2-2 through 2-4 presented in the main report. Tables A-1 through A-3 compare emission factors on a lb/MMBtu basis. These units may be useful for determining if emission factors published in U.S. documents, such as AP-42 or the API Compendium, have been updated. An annual review of the root data sources referenced by EME's GHG Tracking System is recommended to ensure that the emission factors are current.

The approaches used to convert from metric units (tonnes/TJ or grams/GJ) to US-based units of lbs/MMBtu are as follows:

1. To convert from tonne C/TJ to lbs CO_2/MMBtu

$$\frac{\text{tonne C}}{\text{TJ}} \times \frac{2205\,\text{lbs C}}{\text{tonne C}} \times \frac{\text{lb mole C}}{12\,\text{lb C}} \times \frac{\text{lb mole CO}_2}{\text{lb mole C}} \times \frac{44\,\text{lbs CO}_2}{\text{lb mole CO}_2}$$

$$\times \frac{\text{TJ}}{10^{12}\ \text{J}} \times \frac{\text{J}}{0.0009486\,\text{Btu}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} = 8.523\,\text{lbs C/MMBtu}$$

Therefore, to convert from (tonne C/TJ) to (lbs CO_2/MMBtu), multiply by 8.523.

2. To convert from g/GJ to lbs /MMBtu

$$\frac{1\,\text{g CH}_4\text{ or N}_2\text{O}}{\text{GJ}} \times \frac{\text{lb}}{453.593\,\text{g}} \times \frac{\text{GJ}}{10^9\ \text{J}} \times \frac{\text{J}}{0.0009486\ \text{Btu}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}}$$

$$= 0.00232\,\text{lbs CH}_4\text{ or N}_2\text{O/MMBtu}$$

Therefore, to convert from (g/GJ) to (lbs/MMBtu), multiply by 0.00232.

Table A-1. Comparison of CO_2 Emission Factors

All Emission Factors expressed as lb CO_2/MMBtu (HHV)

Fuel Type	Original EME Default Value	WRI/ WBCSD (IPCC-based factors)[9]	WRI/ WBCSD (DOE-based factors)[10]	API Compendium	% Difference (Original EME values versus published factor)	
Alumina Smelter Waste	195.60	176.51			10.82	EME vs. IPCC
Aviation Gasoline		152.75	152.74	152.59		
Biomass (Solid)	268.22	242.10			10.79	EME vs. IPCC
Bitumen		178.13		178.61		
Blast Furnace Gas	625.00	506.27			23.45	EME vs. IPCC
Chlorinated Solvents	183.93	165.99	165.97		10.82	EME vs. DOE
Coal (Anthracite)	240.44	217.23	227.45	227.12	5.71	EME vs. DOE
Coal (Bituminous)	231.49	208.91	205.33	205.29	12.74	EME vs. DOE
Coal (Fly Ash)	195.60	176.51			10.82	EME vs. IPCC
Coal (Lignite)	247.60	223.47	215.43	215.21	14.93	EME vs. DOE
Coal (Sub-bituminous)	231.49	212.16	212.74	212.34	8.81	EME vs. DOE
Coke (Oven Gas)	123.07	99.72			23.42	EME vs. IPCC
Coke (Oven/Gas Coke)	264.64	238.86	238.87	239.24	10.79	EME vs. DOE
Coke (Petroleum)	246.74	222.67	225.17	224.91	9.58	EME vs. DOE
Distillate Fuel		163.56	161.41	161.41		
Distillation Residues	195.60	176.57	176.58		10.78	EME vs. DOE
Ethane	150.69	136.03		131.64	14.47	EME vs. API
Fullers Earth	195.60	176.51			10.82	EME vs. IPCC
Gasoline	169.52	153.04	156.44	157.00	8.36	EME vs. DOE
Kerosene (Jet)	174.98	156.29	156.29	159.42	11.96	EME vs. DOE
Kerosene (Other)	175.83	157.90	159.55		10.20	EME vs. DOE
Liquid Wastes	195.60	176.57	176.58		10.78	EME vs. DOE
LPG	154.35	139.68	139.07	138.69	10.99	EME vs. DOE
Lubricants		161.95	161.94	163.61		
Natural Gas (Dry)	144.89	117.36	117.11	117.09	23.73	EME vs. DOE
Natural Gas (Liquid)	154.35	139.27		139.36	10.76	EME vs. DOE
Oil (Crude)	179.41	161.94		163.83	9.51	EME vs. DOE
Oil (Gas/Diesel)	181.20	165.74		163.61	10.75	EME vs. DOE
Oil (Shale - Liquid)[11]	179.41	161.94, 209.87		162.07	10.70	EME vs. API

[9] The WRI/WBCSD Stationary Combustion tool provides a range of typical emission factors in different units. Emission factors provided on a lower heating value basis are taken from IPCC, Volume II Section 1, 1996.
[10] WRI/WBCSD emission factors provided on a higher heating value basis are taken from DOE, Appendix B, 2000.
[11] The early version of WRI/WBCSD included two emission factors for liquid shale oil. The first value is taken from IPCC, 1996, the second value cites data from Holderbank, 2000.

Table A-1. Continued

All Emission Factors expressed as lb CO_2/MMBTU (HHV)

Fuel Type	Original EME Default Value	WRI/ WBCSD (IPCC-based factors)[9]	WRI/ WBCSD (DOE-based factors)[10]	API Compendium	% Difference (Original EME values versus published factor)	
Orimulsion	197.39	178.13			10.81	EME vs. IPCC
Peat	259.27	234.00	233.99	233.73	10.80	EME vs. DOE
Pitch	195.60	176.57	176.58		10.78	EME vs. DOE
Plastics	183.93	165.97	165.97		10.82	EME vs. DOE
Refinery Gas	172.34	139.61		125.69	37.12	EME vs. API
Residual Fuel Oil	189.30	170.83	173.93	173.75	8.84	EME vs. DOE
Saw Dust Impregnated	183.93	165.97	165.97		10.82	EME vs. DOE
Sludges	195.60	176.57	176.58		10.78	EME vs. DOE
Solid Wastes	195.60	199.88	199.88		-2.14	EME vs. DOE
Solvents	183.93	166.16	165.97		10.82	EME vs. DOE
Synfuel	195.60	176.57	176.58		10.78	EME vs. DOE
Tar	195.60	176.57	176.58		10.78	EME vs. DOE
Tire Derived Fuel	208.13	189.55	189.56		9.80	EME vs. DOE
Waste Tires	208.13	187.85			10.80	EME vs. IPCC
Wood/Wood Waste		221.98	221.98			

[9] The WRI/WBCSD Stationary Combustion tool provides a range of typical emission factors in different units. Emission factors provided on a lower heating value basis are taken from IPCC, Volume II Section 1, 1996.
[10] WRI/WBCSD emission factors provided on a higher heating value basis are taken from DOE, Appendix B, 2000.

Table A-2. Comparison of CH_4 Emission Factors

Fuel	Combustion Technology	Equipment Configuration	EME from IPCC Table 1-15, Volume 3 g CH_4/GJ (LHV)	IPCC Converted to lb CH_4/ MMBTU (HHV)	AP-42 Converted to lb CH_4/ MMBTU (HHV)	AP-42 Reference Table, Year, and Quality Rating	% Difference (AP-42 vs. IPCC)
Coal	Pulverized Bituminous Combustion	Dry Bottom, wall fired	0.7	0.00155	0.00154	Table 1.1-19, 9/98, B	0.48
		Dry Bottom, tangentially fired	0.7	0.00155	0.00154		0.48
		Wet Bottom	0.9	0.00199	0.00192		3.35
	Bituminous Spreader Stokers	With and without re-injection	1	0.00221	0.00231		-4.31
	Bituminous Fluidized Bed Combustor	Circulating Bed	1	0.00221	0.00231		-4.31
		Bubbling Bed	1	0.00221	0.00231		-4.31
	Bituminous Cyclone Furnace		0.2	0.00044	0.00038		14.83
Oil	Residual Fuel Oil/Shale Oil	Normal Firing	0.9	0.00199	0.00187	Table 1.3-3, 9/98, A	6.47
		Tangential Firing	0.9	0.00199	0.00187		6.47
	Distillate Fuel Oil	Normal Firing	0.9	0.00199	0.002		-0.63
		Tangential Firing	0.9	0.00199	0.002		-0.63
	Large Diesel Fuel Engines >447 kW		4	0.00883	0.0081	Table 3.4-1, 10/96, E	9.05
Natural Gas	Boilers		0.1	0.00021	0.00225	Table 1.4-2, 7/98, B	90.72
	Large Gas-Fired Gas Turbines >3MW		6	0.01255	0.0086	Table 3.1-2a, 4/00, C	45.96
	Large Dual-Fired Engines		240	0.50209	0.6	Table 3.4-1, 10/96, E	16.32

Table A-3. Comparison of N_2O Emission Factors

Fuel	Combustion Technology	Equipment Configuration	EME from IPCC Table 1-15, Volume 3 g N_2O/GJ (LHV)	EME and IPCC Converted to lb N_2O/ MMBTU (HHV)	AP-42 Converted to lb N_2O/ MMBTU (HHV)	AP-42 Reference Table, Year, and Quality Rating	% Difference (AP-42 vs. IPCC)
Coal	Pulverized Bituminous Combustion	Dry Bottom, wall fired	1.6	0.00353	0.00115	Table 1.1-19, 9/98, E	206.21
		Dry Bottom, tangentially fired	0.5	0.00110	0.00308		64.12
		Wet Bottom	1.6	0.00353	0.00308		14.83
	Bituminous Spreader Stokers	With and without re-injection	1.6	0.00353	0.00154		129.66
	Bituminous Fluidized Bed Combustor	Circulating Bed	96	0.21199	0.13462	Table 1.1-19, 9/98, B	57.48
		Bubbling Bed	96	0.21199	0.13462		57.48
	Bituminous Cyclone Furnace		1.6	0.00353	0.00346	Table 1.1-19, 9/98, E	2.07
	Lignite Atmospheric Fluidized Bed		42	0.09275	0.15625	Table 1.7-4, 9/98, E	-40.64
Oil	Residual Fuel Oil/Shale Oil	Normal Firing/ Tangential Firing	0.3	0.00066	0.00073	Table 1.3-3, 9/98, B	-9.66
	Distillate Fuel Oil	Normal Firing/ Tangential Firing	0.4	0.00088	0.00079	Table 1.3-3, 9/98, B	12.42
Natural Gas	Boilers		NAV		0.00216	Table 1.4-2, 7/98, E	
	Large Gas-Fired Gas Turbines >3MW		NAV		0.003	Table 3.1-2a, 4/00, E	

Appendix B: Methodology for Converting Between LHV and HHV Bases

Heating value describes the quantity of energy released when a fuel is completely combusted. The difference between gross or higher heating value (HHV) and net or lower heating value (LHV) is the phase of the water in the combustion products: water is in the liquid form for HHV and in the vapor form for LHV. The two heating values are related by the following equation:

$$\mathrm{HHV} = \mathrm{LHV} + \left(\mathrm{n}\bar{h}\right)_{H_2O} \qquad \text{(Equation 1)}$$

where,

- n is the number of moles of water in the products and *h* is the enthalpy of vaporization of water at 25°C.
- Higher heating value (HHV), also referred to as gross calorific value, accounts for condensation of water vapor from the combustion process – the convention commonly used in EPA and DOE documents; and
- Lower heating value (LHV) or net calorific value, includes water in the vapor phase – the convention used by IPCC and other international sources.

Derivation of the correct emission factor conversion is provided below for a solid fuel.

Starting with the IPCC assumption for a solid-based fuel:

$$\mathrm{LHV}\left(\frac{\text{energy}}{\text{mass}}\right) = \mathrm{HHV}\left(\frac{\text{energy}}{\text{mass}}\right) - 5\%\ \mathrm{HHV}\left(\frac{\text{energy}}{\text{mass}}\right)$$

$$\mathrm{LHV}\left(\frac{\text{energy}}{\text{mass}}\right) = \mathrm{HHV}\left(\frac{\text{energy}}{\text{mass}}\right)(1 - 0.05) = 0.95\ \mathrm{HHV}\left(\frac{\text{energy}}{\text{mass}}\right)$$

The heating value is converted to an emission factor as shown:

$$EF\left(\frac{\text{mass } CO_2}{\text{energy}}\right) =$$

$$\frac{\text{X mass C}}{\text{mass fuel}} \times \frac{\text{mol C}}{\text{12 mass units C}} \times \frac{\text{mol } CO_2}{\text{mol C}} \times \frac{\text{44 mass units } CO_2}{\text{mol } CO_2} \times \frac{\text{mass fuel}}{\text{energy fuel}}$$

(Carbon content) (MW Carbon) (Carbon Oxidation) MW CO_2 (1/Heating value

For an emission factor in terms of higher heating value:

$$EF\left(\frac{\text{mass } CO_2}{\text{energy}}\right)_{HHV} = \frac{(44X/12)\text{ mass } CO_2}{\text{mass fuel}} \times \frac{1}{HHV}\left(\frac{\text{mass fuel}}{\text{energy}}\right)$$

Likewise, for an emission factor in terms of lower heating value:

$$EF\left(\frac{\text{mass } CO_2}{\text{energy}}\right)_{LHV} = \frac{(44X/12)\text{ mass } CO_2}{\text{mass fuel}} \times \frac{1}{LHV}\left(\frac{\text{mass fuel}}{\text{energy}}\right)$$

To convert from a HHV-based emission factor to LHV:

$$EF\left(\frac{\text{mass } CO_2}{\text{energy}}\right)_{LHV} = \frac{(44X/12)\text{ mass } CO_2}{\text{mass fuel}} \times \frac{1}{LHV}\left(\frac{\text{mass fuel}}{\text{energy}}\right) \times \frac{LHV}{0.95\text{ HHV}}$$

or expressed more simply:

$$EF_{LHV} = \frac{EF_{HHV}}{0.95}$$

For example, the EME default CO_2 emission factor for bituminous coal is 25.8 tonne C/TJ on a LHV basis. To convert the factor to a HHV basis:

$$EF_{HHV} = EF_{LHV} \times 0.95 = 25.8 \times 0.95 = 24.5 \text{ tonnes C/TJ (HHV)}$$

The same approach would apply for a liquid fuel, except that the heating value of a liquid fuel is typically reported in terms of energy per volume. The fuel carbon content may be available on a mass, volume, or molar basis. As long as the units are internally consistent, the resulting equation to convert from LHV to HHV is the same as presented for the solid fuels. This is illustrated in the following.

Starting with the IPCC assumption for a liquid-based fuel:

$$\mathrm{LHV}\left(\frac{\text{energy}}{\text{volume}}\right) = \mathrm{HHV}\left(\frac{\text{energy}}{\text{volume}}\right) - 5\%\ \mathrm{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)$$

$$\mathrm{LHV}\left(\frac{\text{energy}}{\text{volume}}\right) = \mathrm{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)(1 - 0.05) = 0.95\ \mathrm{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)$$

The heating value is converted to an emission factor, similar to the approach shown for a solid fuel. Additional unit conversions and a fuel density may be required to convert the units appropriately:

$$\mathrm{EF}\left(\frac{\text{mass } CO_2}{\text{energy}}\right) = \underbrace{\frac{\text{mass fuel}}{\text{volume fuel}}}_{\text{(Fuel density)}} \times \underbrace{\frac{\text{X mass C}}{\text{mass fuel}}}_{\text{(Carbon content)}} \times \underbrace{\frac{\text{mol C}}{\text{12 mass units C}}}_{\text{(MW Carbon)}} \times \underbrace{\frac{\text{mol } CO_2}{\text{mol C}}}_{\text{(Carbon Oxidation)}}$$

$$\times \underbrace{\frac{\text{44 mass units } CO_2}{\text{mol } CO_2}}_{(\text{MW } CO_2)} \times \underbrace{\frac{\text{volume fuel}}{\text{energy fuel}}}_{\text{(1/Heating value)}}$$

For an emission factor in terms of higher heating value:

$$\mathrm{EF}\left(\frac{\text{mass } CO_2}{\text{energy}}\right)_{\mathrm{HHV}} = \text{density}\left(\frac{\text{mass fuel}}{\text{volume guel}}\right) \times \frac{(44\mathrm{X}/12)\ \text{mass } CO_2}{\text{mass fuel}} \times \frac{1}{\mathrm{HHV}}\left(\frac{\text{volume fuel}}{\text{energy}}\right)$$

Likewise, for an emission factor in terms of lower heating value:

$$\mathrm{EF}\left(\frac{\text{mass } CO_2}{\text{energy}}\right)_{\mathrm{LHV}} = \text{density}\left(\frac{\text{mass fuel}}{\text{volume fuel}}\right) \times \frac{(44\mathrm{X}/12)\ \text{mass } CO_2}{\text{mass fuel}} \times \frac{1}{\mathrm{LHV}}\left(\frac{\text{volume fuel}}{\text{energy}}\right)$$

To convert from a HHV-based emission factor to LHV:

$$EF\left(\frac{\text{mass } CO_2}{\text{energy}}\right)_{LHV} = \text{density}\left(\frac{\text{mass fuel}}{\text{vol. fuel}}\right) \times \frac{(44X/12)\,\text{mass } CO_2}{\text{mass fuel}} \times \frac{1}{LHV}\left(\frac{\text{vol. fuel}}{\text{energy}}\right) \times \frac{LHV}{0.95\,HHV}$$

or expressed more simply:

$$EF_{LHV} = \frac{EF_{HHV}}{0.95}$$

For example, the EME default CO_2 emission factor for residual fuel oil is 21.1 tonnes C/TJ on a LHV basis. The conversion to a HHV basis is:

$$EF_{HHV} = EF_{LHV} \times 0.95 = 21.1 \times 0.95 = 20.05 \text{ tonnes C/TJ (HHV)}$$

A gas fuel would be treated like a liquid fuel, except that the LHV is 10% lower than the HHV, as shown:

$$LHV\left(\frac{\text{energy}}{\text{volume}}\right) = HHV\left(\frac{\text{energy}}{\text{volume}}\right) - 10\%\ HHV\left(\frac{\text{energy}}{\text{volume}}\right)$$
$$LHV\left(\frac{\text{energy}}{\text{volume}}\right) = HHV\left(\frac{\text{energy}}{\text{volume}}\right)(1 - 0.10) = 0.90\ HHV\left(\frac{\text{energy}}{\text{volume}}\right)$$

Following the same approach as shown for the liquid fuel, the emission factor conversion for a gas fuel is:

$$EF_{LHV} = \frac{EF_{HHV}}{0.90}$$

For example, the EME default CO_2 emission factor for natural gas (dry) is 15.3 tonnes C/TJ on a LHV basis. The conversion to a HHV basis is:

$$EF_{HHV} = EF_{LHV} \times 0.90 = 15.3 \times 0.90 = 13.77 \text{ tonnes C/TJ (HHV)}$$

Appendix C: CO_2 Emissions Estimated on a Fuel Basis for Stationary Combustion Sources

The following text, taken from the API Compendium (API, Section 4.1, 2001), describes the methodology for estimating combustion source CO_2 emissions using fuel specific data. Fuel analyses provided by the supplier will state the fuel composition and heating value. The variability of this information should be assessed for each facility. In general, an annual average can be compiled for each fuel type by weighting each fuel analysis by the quantity of the associated fuel used.

Combustion of hydrocarbons can be represented by the following general reaction, assuming complete combustion:

$$C_xH_yO_z + \left(x + \frac{y}{4} - \frac{z}{2}\right)O_2 \rightarrow (x)\,CO_2 + \left(\frac{y}{2}\right)H_2O \qquad \text{(Equation 4.1-1)}$$

Assuming complete combustion of *X* moles of carbon, *X* moles of carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Methane emissions may also result due to incomplete combustion of the fuel gas, which is emitted as unburned CH_4.

Fuel Combustion Emissions Estimated on a Fuel Basis for Stationary Sources

A material balance approach, based on fuel usage data and fuel carbon analyses, is the preferred technique for estimating emissions from stationary combustion sources. As illustrated in the following example, this approach provides a CO_2 emission estimate based on fuel consumption irrespective of the type of equipment.

EXHIBIT 4.1-1: Sample Calculation for Fuel Basis (Gas Fuel) Combustion Emissions

INPUT DATA:
800 million (10^6) scf/year of natural gas is burned in a combustion device or group of devices. Calculate the annual CO_2 emissions.

(a) Known (or assumed): Higher Heating Value (HHV), Molecular Weight (MW) and Fuel Carbon Content

HHV = 1032 Btu/scf
MW = 17.4
Wt% C = 76.2

CALCULATION METHODOLOGY:
Assume 100% of the carbon in the fuel forms CO_2. A CO_2 emission factor can be developed based on the fuel carbon content:

CO_2 Emission Factor:

$$\frac{17.4\text{ lb fuel}}{\text{lbmole fuel}} \times \frac{\text{lbmole fuel}}{379.3\text{ scf fuel}} \times \frac{\text{scf fuel}}{1032\text{ Btu}} \times \frac{76.2\text{ lb C}}{100\text{ lb fuel}} \times \frac{\text{lbmole C}}{12\text{ lb C}} \times \frac{1\text{ lbmole } CO_2}{1\text{ lbmole C}}$$

$$\times \frac{44\text{ lb } CO_2}{\text{lbmole } CO_2} \times 10^6 = \underline{124.2\text{ lb } CO_2 / 10^6\text{ Btu}}$$

Using this emission factor and the fuel usage data, calculate the annual CO_2 emissions.

CO_2 Emissions:

$$\frac{124.2\text{ lb } CO_2}{10^6\text{ Btu}} \times \frac{800 \times 10^6\text{ scf fuel}}{\text{year}} \times \frac{1032\text{ Btu}}{\text{scf fuel}} = 102{,}539{,}520\text{ lb } CO_2/\text{yr}$$

$$\frac{102{,}539{,}520\text{ lb } CO_2}{\text{year}} \times \frac{\text{tonnes}}{2205\text{ lb}} = \underline{46{,}503\text{ tonnes } CO_2/\text{yr}}$$

(b) Known: Fuel Composition
The gas composition is given below. The weight percent of the fuel components are calculated from the molar composition. (See API Compendium Exhibit 3-3 for an example of this conversion.) The HHVs of the components are available from common data sources.

	Mole %	**MW**	**Wt% (Calculated)**	**HHV (Btu/scf)**
CO_2	0.8	44	2.1	0
CH_4	95.3	16	90.6	1013.2
C_2H_6	1.7	30	3.0	1792
C_3H_8	0.5	44	1.3	2590
C_4H_{10}	0.1	58	0.3	3367
N_2	1.6	28	2.7	0
Fuel Mixture	**100**	**16.84**	**100.0**	**1012.4**

CALCULATION METHODOLOGY:
The HHV of the fuel mixture shown above is based on a weighted average of the individual component HHVs and mole fractions (or volume fraction for an ideal gas).

$$\text{HHV}_{\text{Mixture}} = \sum_{i=1}^{\#\text{ components}} \left(\text{Mole fraction}_i \times \text{HHV}_i\right)$$

$$= \left[(0.008 \times 0) + (0.953 \times 1013.2) + (0.017 \times 1792) + (0.005 \times 2590) + (0.001 \times 3367) + (0.016 \times 0)\right]$$

$$= \underline{1012.4\text{ Btu/scf}}$$

Similarly, the carbon content of the fuel mixture is a weighted average of the individual component carbon contents. This is determined by first calculating the wt% carbon of each of the fuel components, which is the molecular weight of carbon (12 lb/lbmole) times the number of moles of carbon and divided by the molecular weight of the compound. This is shown below for ethane (C_2H_6).

$$\frac{12\text{ lb C}}{\text{lbmole C}} \times \frac{2\text{ lbmoles C}}{\text{lbmole }C_2H_6} \times \frac{\text{lbmole }C_2H_6}{30\text{ lb }C_2H_6} = \underline{0.8\text{ lb C/lb }C_2H_6} \times 100\% = 80\%\text{ C}$$

The carbon content of the fuel mixture is then calculated as:

$$\text{Wt\%C}_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\#\text{ components}} \left(\text{Wt\%}_i \times \text{Wt\%C}_i\right)$$

$$= \frac{1}{100} \times \left[(2.1 \times 27.3) + (90.6 \times 75) + (3 \times 80) + (1.3 \times 81.8) + (0.3 \times 82.8) + (2.7 \times 0)\right]$$

$$= \underline{72.24\text{ Wt\% C}}$$

	Wt% (Calculated)	Carbon Content (wt% C)
CO_2	2.1	27.3
CH_4	90.6	75.0
C_2H_6	3.0	80.0
C_3H_8	1.3	81.8
C_4H_{10}	0.3	82.8
N_2	2.7	0
Fuel Mixture	**100.0**	**72.24**

From the information above, a fuel specific emission factor for CO_2, in terms of energy input, can be calculated assuming all of the carbon in the fuel forms CO_2:

$$\frac{16.84\text{ lb fuel}}{\text{lbmole fuel}} \times \frac{\text{lbmole fuel}}{379.3\text{ scf fuel}} \times \frac{\text{scf fuel}}{1012.4\text{ Btu}} \times \frac{0.7224\text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12\text{ lb C}} \times \frac{\text{lbmole }CO_2}{\text{lbmole C}}$$

$$\times \frac{44\text{ lb }CO_2}{\text{lbmole }CO_2} \times 10^6 = \underline{116.2\text{ lb }CO_2/10^6\text{ Btu}}$$

Using this emission factor and the fuel usage, calculate the annual CO_2 emissions:

$$\frac{116.2\text{ lb }CO_2}{10^6\text{ Btu}} \times \frac{1012.4\text{ Btu}}{\text{scf fuel}} \times \frac{800 \times 10^6\text{ scf fuel}}{\text{yr}} = 94{,}112{,}704\text{ lb }CO_2/\text{yr}$$

$$\frac{94{,}112{,}704\text{ lb }CO_2}{\text{yr}} \times \frac{\text{tonne}}{2205\text{ lb}} = \underline{42{,}681\text{ tonnes }CO_2/\text{yr}}$$

Note that the two gas combustion approaches presented here produce different results based on the information provided.

EXHIBIT 4.1-2(a): Sample Calculation for Fuel Basis (Liquid Fuel) Combustion Emissions

INPUT DATA:
4 million (10^6) gallons per year of No. 6 residual fuel is burned in a combustion device or group of devices. Calculate a site specific CO_2 emission factor first, and then the annual CO_2 emissions for a site where detailed fuel information is known.

Known (or assumed): Higher Heating Value (HHV), Density and Fuel Carbon Content

HHV = 160,000 Btu/gallon
Liquid Density = 8.3 lb/gallon
Wt% C = 92.3

CALCULATION METHODOLOGY:
Since the carbon content and higher heating value are known, a site-specific emission factor can be calculated for this fuel, assuming all the carbon in the fuel forms CO_2:

$$\frac{8.3\text{ lb fuel}}{\text{gal. fuel}} \times \frac{\text{gal. fuel}}{160{,}000\text{ Btu}} \times \frac{92.3\text{ lb C}}{100\text{ lb fuel}} \times \frac{44\text{ lb CO}_2}{12\text{ lb C}} \times 10^6 = \underline{175.6\text{ lb CO}_2/10^6\text{ Btu}}$$

Using this emission factor and the fuel usage data, the annual CO_2 emissions can be calculated next:

$$\frac{175.6\text{ lb CO}_2}{10^6\text{ Btu}} \times \frac{4\times10^6\text{ gal. fuel}}{\text{year}} \times \frac{160000\text{ Btu}}{\text{gal. fuel}} = 112{,}384{,}000\text{ lb CO}_2/\text{yr}$$

$$\frac{112{,}384{,}000\text{ lb CO}_2}{\text{year}} \times \frac{\text{tonnes}}{2205\text{ lb}} = \underline{50{,}968\text{ tonnes CO}_2/\text{yr}}$$

Note, the higher heating value is not needed to calculate the annual CO_2 emissions in this example since the fuel carbon content is known. As an alternative, the CO_2 emissions can be calculated based on the density and carbon content:

$$\frac{4\times10^6\text{ gal. fuel}}{\text{year}} \times \frac{8.3\text{ lb fuel}}{\text{gal. fuel}} \times \frac{92.3\text{ lb C}}{100\text{ lb fuel}} \times \frac{44\text{ lb CO}_2}{12\text{ lb C}} \times \frac{\text{tonnes}}{2205\text{ lb}} = \underline{50{,}956\text{ tonnes CO}_2/\text{yr}}$$

EXHIBIT 2(b): Sample Calculation for Fuel Basis (Liquid Fuel) Combustion Emissions

Known (or assumed): Higher Heating Value (HHV) only

If only the fuel type is known, an emission factor can be obtained from API Compendium Table 4-1. The higher heating value (HHV) must be known or estimated for the fuel type.

CALCULATION METHODOLOGY:
The emission factor for residual fuel oil from API Compendium Table 4-1 is 47.4 lb C/10^6 Btu. Convert this to a CO_2 basis:

$$\frac{47.4\ \text{lb C}}{10^6\ \text{Btu}} \times \frac{44\ \text{lb CO}_2}{12\ \text{lb C}} = 173.8\ \text{lb CO}_2\ /10^6\ \text{Btu}$$

Note the difference between this generic emission factor and the site-specific emission factor of 175.6 lb CO_2/10^6 Btu calculated in Exhibit 4.1-2(a).

Using the generic emission factor and fuel usage data, calculate the annual CO_2 emissions.

$$\frac{173.8\ \text{lb CO}_2}{10^6\ \text{Btu}} \times \frac{4\times10^6\ \text{gal. fuel}}{\text{year}} \times \frac{160{,}000\ \text{Btu}}{\text{gal. fuel}} = 111{,}232{,}000\ \text{lb CO}_2\ /\ \text{yr}$$

$$\frac{111{,}232{,}000\ \text{lb CO}_2}{\text{year}} \times \frac{\text{tonnes}}{2205\ \text{lb}} = \underline{50{,}445\ \text{tonnes CO}_2/\text{yr}}$$

Appendix D: CH_4 Emission Factors For Non-Combustion Sources

Non-combustion sources of CH_4 emissions consist of:

- Fugitive emissions – which refer to gas leakage from equipment components, such as valves, flanges, seals, or related equipment; and
- Process vents – which refer to gas that is released directly to the atmosphere.

EME's operations may include CH_4 emission sources from equipment associated with supplying natural gas to the electric generators (includes both fugitive sources and process vents), cooling towers, and anaerobic wastewater treatment. This section provides excerpts from the API Compendium for these potential non-combustion CH_4 emission sources. Emissions from these sources are expected to be small compared to EME's combustion emissions, but are provided here for completeness.

Facility Level Average Fugitive Emission Factors

The simplest method for estimating fugitive CH_4 emissions from natural gas service equipment/operations is by using average facility-level emission factors, as presented in Table D-1. The user simply needs to know the type of facility and its throughput or major equipment counts to use these factors. These facility-level factors were developed by aggregating component emission measurements and activity factors for the facility, primarily for upstream gas industry facilities (GRI, 1999). This approach should provide a reasonable estimate of the fugitive equipment leaks emissions from the facility, consistent with the relative contribution of emissions from these sources compared to combustion sources.

Table D-1. Facility-Level Average Fugitive Emission Factors

Industry Segment	Source	Emission Factor
Gas distribution	Metering and Pressure Regulating Stations	8,740 lb CH_4/station-yr
	Customer meters	5.452 lb CH_4/meter-yr

Source: GRI, *GRI-GHGCalc™ Version 1.0*, Software, GRI-99/0086, December 1999.

Distribution Pipeline Process Vents

Process vent emissions from natural gas distribution associated with EME operations can be grouped into two categories: emissions resulting from maintenance activities or upset conditions, and pipeline dig-ins. Maintenance activities may result in the intentional release of process gas to the environment to provide safe working conditions. For example, depressurization to the atmosphere of a distribution pipeline segment may be required in order to conduct repairs. Gas releases from upset conditions may result from conditions that automatically trigger the depressurization of process equipment to ensure safe operating conditions, such as with pressure relief valves. Pipeline dig-in emissions result from the unintentional release of natural gas when a pipeline is damaged from excavation equipment.

Table D-2 provides simple emission factors to account for these emissions based on the total length of distribution pipeline and/or services within EME's operational control.

Table D-2. Average Process Vent Emission Factors for Distribution Pipeline Systems

Source	Emission Factors[a]	Reference
Maintenance/Upsets (based on mains and services length)	5.667 lb CH_4/mile-yr	GRI/EPA study, Volume 2, 1996
Pipeline Dig-ins (based on mains and services length)	67.12 lb CH_4/mile-yr	

Anaerobic Water Treatment

Anaerobic water treatment processes refer to those that are operated in the absence of oxygen. These processes produce CH_4, and to a much lesser degree CO_2 and N_2O, as byproducts of the digestion of larger organic molecules. This emission source is considered to be very minor since most electric utilities use wastewater ponds open to the atmosphere. However, a calculation methodology is provided for the few facilities where this may apply.

For facilities where CH_4 is not captured from an anaerobic water treatment system, US EPA presents a relatively simple method for estimating CH_4 emissions in AP-42 Section 4.3.5.2. The following equation is used:

$$E_{CH_4} = Q \times \left(\frac{\text{lbBOD}_5}{\text{ft}^3\text{wastewater}} \right) \times \left(\frac{0.22\text{lbCH}_4}{\text{lbBOD}_5} \right) \times F_{AD} \times 365 \qquad \text{(Equation 2)}$$

where,

E_{CH4} = emission rate of CH_4 in pounds per year
Q = wastewater flow rate in cubic feet per day
BOD_5 = biological oxygen demand measured using the standard five day test
F_{AD} = fraction anaerobically digested
365 = days per year

A site-specific value for BOD_5 loading should be available from facility wastewater treating staff but, if it is not, EPA suggests a default value of 0.25 pounds BOD_5 per cubic foot of wastewater for the oil and gas industry (the electric utility industry is not listed in AP-42 Table 4.3-5, 1998). The fraction anaerobically digested is that part of the wastewater flow that is routed to anaerobic treatment as opposed to aerobic treatment.

Alternatively, the Intergovernmental Panel on Climate Change (IPCC) provides an anaerobic wastewater treatment emissions approach based on chemical oxygen demand (COD) (IPCC, 2000). The COD default factor for maximum CH_4 producing capacity is:

$$\boxed{0.25 \text{ kg } CH_4/\text{kg COD}}$$

IPCC also provides a typical COD production rate of 1 gram of COD per liter of wastewater generation, with the COD value ranging between 0.4 and 1.6 g COD/L.

The emission rates for CO_2 and N_2O are considered to be negligible compared to the CH_4 emission rate. No equation has been found to estimate these emissions.

An example calculation for CH_4 emissions from anaerobic water treatment follows, taken from the API Compendium, Exhibit 4.3-4.

Sample Calculation for Anaerobic Treatment Approach

INPUT DATA:
A wastewater treatment system processes 870,000 cubic feet per day, with 10% of the water going to anaerobic treatment. The BOD_5 level of the influent averages 0.3 pounds per cubic foot.

CALCULATION METHODOLOGY:
Using Equation 2, the estimated emissions would be:

$$E_{CH_4} = 870{,}000 \frac{\text{ft}^3}{\text{day}} \times \left(\frac{0.3 \text{ lb BOD}_5}{\text{ft}^3 \text{wastewater}}\right) \times \left(\frac{0.22 \text{ lb CH}_4}{\text{lb BOD}_5}\right) \times \left(\frac{0.1 \text{ ft}^3 \text{ anaerobic}}{\text{ft}^3 \text{ processed}}\right) \times 365 \frac{\text{days}}{\text{year}} \times \frac{\text{tonne}}{2205 \text{ lb}}$$
$$= \underline{950.5 \text{ tonne CH}_4/\text{yr}}$$

Using IPCC's approach and assuming the default COD rate, the estimated emissions would be:

$$E_{CH_4} = 870{,}000 \frac{\text{ft}^3}{\text{day}} \times \left(\frac{0.1 \text{ ft}^3 \text{ anaerobic}}{\text{ft}^3 \text{processed}}\right) \times 365 \frac{\text{days}}{\text{year}} \times \frac{28.32 \text{ L}}{\text{ft}^3} \times \frac{1 \text{ g COD}}{\text{L}} \times \frac{0.25 \text{ g CH}_4}{\text{g COD}} \times \frac{\text{tonne CH}_4}{1 \times 10^6 \text{ g}}$$
$$= \underline{224.8 \text{ tonne CH}_4/\text{yr}}$$

Appendix E: Allocation of Emissions Between Electricity and Steam Generation

The WRI/WBCSD GHG Protocol Initiative (WRI/WBCSD, 2001) includes an approach for allocating combustion emissions between energy streams when these streams are used by two or more different parties. This approach is only applicable where EME would want to track emissions associated with cogenerated steam and electricity exported to separate customers. This approach does not apply if the steam is used to produce additional electricity or both steam and electricity are sold to the same customer.

The WRI/WBCSD approach for allocating emissions associated with the cogeneration of electricity and steam assigns the emissions to the energy streams in proportion to their contribution to the total work potential. The work potential for steam is calculated from the specific enthalpy (H) and specific entropy (S) of the stream. This approach sums the work potential of all streams and allocates the total emissions to the individual streams.

The first step is to calculate the total direct CO_2 emissions from fuel combustion at the cogeneration facility. For EME, the combustion emission factor would be multiplied by the energy input value associated with the fuel requirements to calculate the direct emissions. The second step is to calculate the work potential of the steam, using 212°F saturated water as the reference basis, and 700°F and 600 psia for the process steam. The enthalpy and entropy of the steam can be determined from a steam table at the reference and actual conditions. The work potential of the steam is calculated using the following equation:

$$\text{Steam work potential (Btu/lb)} = (H_i - H_{ref}) - (T_{ref} + 460) \times (S_i - S_{ref})$$

where:
H_i = specific enthalpy of the process steam (BTU/lb)
H_{ref} = specific enthalpy at the reference conditions (BTU/lb)
T_{ref} = reference temperature (R)
S_i = specific entropy of the process steam (BTU/lb R)
S_{ref} = specific entropy at the reference conditions (BTU/lb R)

The third step is to apply the allocation approach for electricity imports/exports from cogeneration used in the WRI/WBCSD GHG Protocol.

$$CO_2 \text{ Eq. EF from electricity (tonnes } CO_2 \text{ Eq./MW-hr electricity)} = \frac{CO_2 \text{ Eq. direct emissions (tonnes } CO_2 \text{ Eq./yr)}}{\left[\text{Work potential}_{\text{steam}}\left(\frac{\text{MW-hr}}{\text{yr}}\right) + \text{Work potential}_{\text{electricity}}\left(\frac{\text{MW-hr}}{\text{yr}}\right)\right]}$$

The same approach is used for allocating emissions associated with steam imports/exports from cogeneration.

$$\text{CO}_2\ \text{Eq. EF from steam (tonnes CO}_2\ \text{Eq./MW-hr steam)} = \frac{\text{CO}_2\ \text{Eq. direct emissions (tonnes CO}_2\ \text{Eq./yr)}}{\left[\text{Work potential}_{\text{steam}}\left(\frac{\text{MW-hr}}{\text{yr}}\right) + \text{Work potential}_{\text{electricity}}\left(\frac{\text{MW-hr}}{\text{yr}}\right)\right]}$$

An example is provided to illustrate this approach.

A cogeneration facility consumes 8,131,500 million BTU of natural gas, producing 3,614,000 million BTU steam at 700 °F and 600 psia and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. The cogeneration facility itself requires 38,500 megawatt-hr to operate, with the net electricity (metered at the custody transfer point) sold to the electric grid. Produced steam is sold to a nearby refinery.

Post-Project Emissions Calculation:

Step 1: Direct Emissions from Cogeneration:

Combustion emissions are calculated based on the natural gas consumed using the EME (corrected) emission factors for CO_2 (Table 2-2) and the AP-42 CH_4 emission factor for large gas-fired turbines (Table 2-3):

$$\text{CO}_2:\ 8{,}131{,}500 \times 10^6\ \text{Btu} \times \frac{\text{J}}{0.0009486\ \text{Btu}} \times \frac{\text{TJ}}{10^{12}\ \text{J}} \times \frac{13.77\ \text{tonnes C}}{\text{TJs}} \times \frac{44\ \text{tonnes CO}_2}{12\ \text{tonnes C}} = 432{,}806\ \text{tonnes CO}_2$$

$$\text{CH}_4:\ 8{,}131{,}500 \times 10^6\ \text{Btu} \times \frac{\text{J}}{0.0009486\ \text{Btu}} \times \frac{\text{GJ}}{10^9\ \text{J}} \times \frac{3.7\ \text{g CH}_4}{\text{GJ}} \times \frac{\text{tonnes CH}_4}{10^6\ \text{g CH}_4} = 31.7\ \text{tonnes CH}_4$$

$$\text{CO}_2\ \text{Eq.}:\ 432{,}806 + \left(31.7 \times \frac{21\ \text{tonnes CO}_2\ \text{Eq.}}{\text{tonnes CH}_4}\right) = 433{,}471\ \text{tonnes CO}_2\ \text{Eq.}$$

Step 2: Steam Work Potential

Steam work potential requires the enthalpy and entropy of the steam at both actual and reference conditions. These values can be determined using a steam table.

Enthalpy:
Steam, 600 psia, 700 °F = 1,350 BTU/lb (H_i)
Saturated Water, 212 °F = 180 BTU/lb (H_{ref})

Entropy:
Steam, 600 psia, 700 °F = 1.5872 BTU/lb-R (S_i)
Saturated Water, 212 °F = 0.31213 BTU/lb-R (S_{ref})

The work potential of the steam is then calculated using these values:

$$\text{Steam work potential (Btu/lb)} = (H_i - H_{ref}) - (T_{ref} + 460) \times (S_i - S_{ref})$$

$$= (1{,}350 - 180)\frac{\text{BTU}}{\text{lb}} - \left[(212 + 460)\text{R} \times (1.5872 - 0.31213)\frac{\text{BTU}}{\text{lb-R}}\right] = 313.2 \text{ BTU/lb}$$

In addition, the steam needs to be expressed on a mass basis to apply the WRI/WBCSD equations.

$$3{,}614{,}000 \times 10^6 \text{ BTU steam} \times \left(\frac{\text{lb steam}}{1{,}350 \text{ BTU}_{\text{steam conditions}} - 180 \text{ BTU}_{\text{reference conditions}}}\right)$$
$$= 3.089 \times 10^9 \text{ lbs steam}$$

Next, the mass of steam and the steam work potential are combined and converted to MW-hr:

$$3.089 \times 10^9 \text{ lbs steam/yr} \times \left(\frac{313.2 \text{ BTU}}{\text{lb steam}}\right) \times \frac{\text{kW-hr}}{3412 \text{ BTU}} \times \frac{\text{MW-hr}}{1000 \text{ kW-hr}}$$
$$= 283{,}550 \text{ MW-hr/yr}$$

<u>Step 3: Calculate Electricity and Steam Emission Factors</u>

The third step is to apply the WRI/WBCSD equation for allocating emissions between the electricity and steam energy to generate emission factors.

Allocation =

$$\frac{CO_2 \text{ Eq. direct emissions (tonnes } CO_2 \text{ Eq./yr)}}{\left[\text{Work potential}_{\text{steam}}\left(\frac{\text{MW-hr}}{\text{yr}}\right) + \text{Work potential}_{\text{electricity}}\left(\frac{\text{MW-hr}}{\text{yr}}\right)\right]}$$

$$= \frac{433{,}471 \text{ tonnes } CO_2 \text{ Eq.}}{283{,}550 \text{ MW-hr}_{\text{steam}} + 1{,}100{,}600 \text{ MW-hr}_{\text{electricity}}} = 0.313 \text{ tonne } CO_2 \text{ Eq./MW-hr}$$

Step 4: Apply Emission Factor to Estimate Emissions

The emissions associated with direct and indirect electricity are determined by applying the appropriate onsite and exported MW-hrs to this emission factor.

CO_2 Equivalent Emissions for Onsite Electricity Usage:

$$\frac{0.313 \text{ tonnes } CO_2 \text{ Eq.}}{\text{MW - hr electricity}} \times 38{,}500 \text{ MW - hr} = 12{,}050 \text{ tonnes } CO_2 \text{ Eq.}$$

CO_2 Equivalent Emissions for Exported Electricity:

$$\frac{0.313 \text{ tonnes } CO_2 \text{ Eq.}}{\text{MW - hr electricity}} \times (1{,}100{,}600 - 38{,}500) \text{ MW - hr} = 332{,}437 \text{ tonnes } CO_2 \text{ Eq.}$$

CO_2 Equivalent Emissions for Exported Steam:

$$\frac{0.313 \text{ tonnes } CO_2 \text{ Eq.}}{\text{MW - hr steam}} \times 283{,}540 \text{ MW - hr} = 88{,}748 \text{ tonnes } CO_2 \text{ Eq.}$$

As summarized in Table E-1, the sum of the emissions assigned to onsite exported steam and electricity should equal the total direct emissions from combustion. The minor difference is due to round off in the calculations.

Table E-1. Summary of Cogeneration Emissions – WRI/WBCSD Approach

	Onsite Energy Usage	Energy Exports
	Emissions, tonnes CO_2 Eq.	Emissions, tonnes CO_2 Eq.
Steam		88,748
Electricity	12,050	332,437
TOTAL	433,235 tonnes CO_2 Eq.	
Cogeneration Fuel Consumption	433,471 tonnes CO_2 Eq.	

Appendix F: Country-based Electricity Generation Data

The International Energy Administration (IEA) reports country specific electricity generation information on an annual basis (IEA, 2002). Table F-1 summarizes both electric generation output by fuel type and heat input associated with fuels used to generate electricity for the countries of interest. The heat input values were confirmed to be associated only with electricity generation and not thermal energy production. A fuel specific heat rate can be determined by dividing the heat input value for each fuel type by the TW-hr of electricity generation. These heat rates are used to convert between the output (i.e., electric generation) basis and heat input basis.

Table F-1. Summary of Year 2000 Electricity Production Information

	Australia			Italy		
Fuel	**Heat Input PJ (HHV)**	**Electricity Generated, TW-hr**	**Heat Rate, BTU/kW-hr**	**Heat Input PJ (HHV)**	**Electricity Generated, TW-hr**	**Heat Rate, BTU/kW-hr**
Hard Coal	1,108	110.2	9,541	263.1	25.99	9,604
Brown Coal	634.3	50.35	11,950	2.205	0.28	7,470
Peat	0	0		0	0	
Coal Gases	0.63	0.07	8,537	50.4	4.25	11,249
Liquid Fuels	21.94	2.7	7,710	836.1	85.9	9,233
Natural Gas	210.2	26.2	7,611	869.3	101.4	8,132
Solid Biomass	38.54	1.32	27,639	1.575	0.22	6,791
Industrial Waste	0	0		3.15	0.32	9,338
Municipal Waste	0	0		7.56	0.8	8,964
Bio gas	6.09	0.38	15,203	5.67	0.57	9,436
Nuclear	NA	0		NA	0	
Hydro	NA	17.1		NA	50.9	
Geothermal		0			4.7	
Solar	NA	0		NA	0	
Wind	NA	0.1		NA	0.6	
Other fuel	NA	0		NA	0.8	
TOTAL	1,923	208.4		2,039	276.6	

NA = not applicable

Source of electric generation information – IEA Electricity Information Database, "Summary of Electricity Production and Consumption (TWhr)." (IEA, 2002).

Source of heat input information – IEA Electricity Information Database, "Fuel Use for Electricity and Heat Production, by Country, 2000." (IEA, 2002). Heat input data were corrected to exclude heat not converted to electricity based on data from IEA Electricity Information Database "Gross Electricity and Heat Production from Combustible Fuels by Country, 2000". This affected only Spain and US data.

Table F-1. Continued

	New Zealand			Philippines		
Fuel	**Heat Input PJ (HHV)**	**Electricity Generated, TW-hr**	**Heat Rate, BTU/kW-hr**	**Heat Input PJ (HHV)**	**Electricity Generated, TW-hr**	**Heat Rate, BTU/kW-hr**
Hard Coal	10.71	1.01	10,059	176.6	16.66	10,056
Brown Coal	0	0				
Peat	0	0				
Coal Gases	0	0				
Liquid Fuels	0	0				
Natural Gas	97.3	9.3	9,925	95.76	9.19	9,884
Solid Biomass	6.72	0.48	13,280	0.4	0.02	18,972
Industrial Waste	0	0				
Municipal Waste	0	0				
Bio gas	1.26	0.11	10,866			
Nuclear	NA	0		NA	0	
Hydro	NA	24.6		NA	7.8	
Geothermal		2.8			11.63	
Solar	NA	0		NA	0	
Wind	NA	0.1		NA	0	
Other fuel	NA	0.6		NA		
TOTAL	115.99	39		272.8	45.3	

	Spain			UK		
Fuel	**Heat Input PJ (HHV)**	**Electricity Generated, TW-hr**	**Heat Rate, BTU/kW-hr**	**Heat Input PJ (HHV)**	**Electricity Generated, TW-hr**	**Heat Rate, BTU/kW-hr**
Hard Coal	665.2	67.61	9,333	1,206	119.96	9,537
Brown Coal	122.7	11.48	10,143	0	0	
Peat	0	0		0	0	
Coal Gases	17.85	1.76	9,621	40.11	4.36	8,727
Liquid Fuels	196.9	22.6	8,264	44.63	5.6	7,559
Natural Gas	123.1	20.2	5,781	1,126	146.8	7,273
Solid Biomass	29.94	1.36	20,880	11.55	0.7	15,652
Industrial Waste	3.255	0.27	11,436	0	0	
Municipal Waste	8.61	0.746	10,747	17.22	1.1	14,850
Bio gas	3.78	0.38	9,436	33.18	2.56	12,295
Nuclear	NA	62.2		NA	85.1	
Hydro	NA	31.8		NA	7.8	
Geothermal		0			0	
Solar	NA	0		NA	0	
Wind	NA	4.7		NA	0.9	
Other fuel	NA	0		NA	0	
TOTAL	1,171	225.1		2,478	374.9	

Table F-1. Continued

	US		
Fuel	**Heat Input PJ (HHV)**	**Electricity Generated, TW-hr**	**Heat Rate, BTU/kW-hr**
Hard Coal	20,732	2,005	9,807
Brown Coal	1,037	97.22	10,116
Peat			
Coal Gases	91.82	7.55	11,537
Liquid Fuels	1,323	124.7	10,065
Natural Gas	7,103	630.3	10,690
Solid Biomass	1,610	41.62	36,693
Industrial Waste	149.3	6.55	21,618
Municipal Waste	278.4	15.65	16,877
Bio gas	81.78	4.98	15,500
Nuclear	NA	799.9	
Hydro	NA	275.1	
Geothermal		14.7	
Solar	NA	0.9	
Wind	NA	5.6	
Other fuel	NA	0	
TOTAL	33,408	4030.3	

Using data from Table F-1, three approaches are examined for developing composite grid-based emission factors for each country:

1. Generation-specific emission factors can be combined with the electricity generation data shown above;
2. Heat rate values from above can be used to convert generation-specific emission factors to a heat input basis; or
3. Heat input based emission factors can be combined with the fuel heat input data shown above.

For each method, a weighted average emission factor is calculated from the fuel specific information. Emission factors are developed for each of the three methods in the following sub-sections.

Another source of information on emissions resulting from electricity in other countries are available in the Greenhouse Gas Protocol by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) (WRI/WBCSD, 2001). The emission factors provided by WRI/WBCSD are based on fuel consumption and generation methods to produce both electricity and heat, where the total CO_2 emissions are derived from the national fuel usage, carbon content and heating value of the fuel, and divided by the sum of energy output from both electricity and heat. Note, however, that the actual mix of generation methods and fuels used for electricity versus heat can differ significantly within a country, such that these emission factors may not be appropriate for calculating emissions associated with electricity usage only. Therefore, the IEA data developed specifically from electricity generation information is recommended over the WRI/WBCSD published emission factors.

Generation Specific Emission Factors

This approach uses emission factors reported in terms of electricity generated for different fuel types and common electric generation methods. The root emission factors are presented in Table F-2.

Table F-2. Electricity Usage Emission Factors by Generation Method

Location	Tonnes/MW-hr		
	CO_2	**CH_4**	**N_2O**
Gas - Combined Cycle	0.432	6.80E-06	2.86E-05
Gas - Combustion Turbine	0.707	7.26E-05	1.09E-04
Gas - Steam Turbine	0.439	2.27E-05	0
Oil - Combined Cycle	0.603	5.90E-06	1.22E-04
Oil - Combustion Turbine	0.975	9.52E-06	1.25E-04
Oil - Steam Turbine	0.659	9.07E-07	0
Pulverized Coal	0.893	1.81E-05	1.54E-04
Municipal Solid Waste Boiler[a]	1.700	9.07E-06	2.49E-04
Wood Waste Biomass Boiler[a]	1.542	6.35E-05	2.49E-04
Renewables (wind, hydro, solar, and nuclear)	0	0	0

Source: US Department of Energy, Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992, Volume I, DOE/PO-0028, Washington, D.C. October 1994.

[a] These biofuels contain carbon that is not part of the natural carbon balance and does not contribute to atmospheric concentrations of CO_2.

Table F-2 footnotes the municipal solid waste boiler and wood waste biomass boiler emission factors, indicating that these sources are carbon neutral. This is consistent with policies adopted by IPCC and EPA, where CO_2 emissions resulting from biomass combustion are not included based on the assumption that biogenic carbon emitted is offset by the growth of new biomass. Therefore, in developing the national emission factors, zero CO_2 emissions are applied for these sources. However, the CH_4 and N_2O emission factors shown in Table F-2 are included in the calculations.

One generation method not assessed in Table F-2 is geothermal. Although this is considered a renewable energy source, the geothermal gas can contain high concentrations of CO_2. The

International Geothermal Association conducted a survey to determine CO_2 emissions from geothermal power plants from around the world (Bertani and Thain, 2001). Emission data were collected from 85 geothermal power plants operating in 11 countries, representing 85% of the worldwide geothermal power plant capacity. From this data, the MW weighted CO_2 emission rate of 122 grams per kWhr of generation was calculated. This value is used to assess the contribution of geothermal CO_2 emissions in developing the output-based emission factors.

Weighted average emission factors are calculated for each country by combining the emission factors from Table F-2 with the electricity generation by fuel type from Table F-1. This weighted average approach is represented by Equation 3:

$$\text{National Electric EF} = \sum \frac{\text{TW - hr for Fuel Type}_i}{\text{TW - hr Total}} \times \text{Base EF for Fuel/Generation Type}_i \left(\frac{\text{tonnes}}{\text{MW - hr}}\right)$$

where, EF = emission factor. (Equation 3)

The percent contribution of each fuel type to electricity generation is shown in Table F-3. These percentages are calculated by dividing the TW-hr generated for each fuel by the total country TW-hr.

Table F-3. Gross Electric Production by Fuel Type, 2000 Data

	Australia	Italy	New Zealand	Philippines	Spain	UK	US
Total Gross Generation, TW-hr	208.4	276.6	39	45.3	225.1	374.9	4030.3
% Hard Coal	52.9%	10.9%	2.6%	36.8%	30.8%	33.2%	49.9%
% Brown Coal	24.2%	0.1%	0%	0%	5.1%	0%	2.4%
% Oil	1.3%	31.1%	0%	20.3%	10.0%	1.5%	3.1%
% Natural Gas	12.6%	36.7%	23.8%	0%	9.0%	39.2%	15.6%
% Geothermal	0%	1.7%	7.2%	25.7%	0%	0%	0.4%
% Wind, Hydro, Solar, & Nuclear	8.3%	18.6%	63.3%	17.2%	43.8%	25.0%	26.8%
% Combustible Renewables	0.8%	0.3%	1.5%		0.8%	0.9%	1.2%
% Municipal Waste	0%	0.3%	0%		0.3%	0.3%	0.4%
% Other Fuels and Waste	0%	0.4%	1.5%		0.1%	0%	0.2%

Additional IEA information indicates that the majority of the electrical capacity for the countries of interest is by steam turbines, followed by combined cycle (see Table F-4). In calculating the national emission factors, the oil steam turbine emission factor is applied to electric generation by oil fuels and the gas combined cycle emission factor is applied to electric generation by gas fuels. As mentioned previously, the wood waste biomass emission factors for CO_2 are not included, but the CH_4 and N_2O emission factors are applied to electricity generation by combustible renewables. Similarly, the CO_2 emissions from municipal solid waste are zero, while the DOE CH_4 and N_2O emission factors are applied to this electric generation. The municipal solid waste boiler emission factors are also applied to the "other fuels and waste" category of electric generation.

Table F-4. Summary of Maximum Electrical Capacity, MWe

Year 2000 MWe	Australia	Italy	New Zealand	Spain	UK
Total Capacity from Combustible Fuels	33,598	54,034	2,512	2,163	55,930
Capacity based on generation type, for all combustible fuels					
Steam Turbine	29,501	40,048	1,680	20,093	35,221
IC Engine	285	833	1	492	0
Turbine	3,133	5,314	477	476	1,243
Combined Cycle	679	7,839	354	302	19,349
Other	0	0	0	0	117

Source – IEA Electricity Information Database, "OECD Net maximum Electricity Capacity (2002 Edition)" (IEA, 2002).

Calculation of the national emission factors is illustrated below for Italy.

Electricity Emission Factor Development for Italy – Generation Based Approach

CALCULATION METHODOLOGY:

Table F-1 provides the year 2000 fuel mix for electricity production in Italy. Table F-2 provides the emission factors for different electricity generation types (DOE, 1994). In the table below, the weighted emission factors are calculated by multiplying the percent contribution to electricity generation of each fuel/generation type by the base emission factor (from Table F-2), as shown in Equation 4 for CO_2:

$$\text{Weighted } CO_2 \text{ EF} = \text{Base } CO_2 \text{ EF} \times \frac{\%\ \text{Contribution}}{100} \qquad \text{(Equation 4)}$$

The weighted emission factors are then summed for all of the fuel types to result in the total average emission factor for each greenhouse gas.

Fuel/ Generation Type	% Contribution to Electricity Generation	Tonnes/MW-hr					
		Base CO_2 EF	Weighted CO_2 EF	Base CH_4 EF	Weighted CH_4 EF	Base N_2O EF	Weighted N_2O EF
Hard coal + coal gases + brown coal	11.0	0.893	0.0982	1.814E-5	1.995E-6	1.542E-4	1.696E-5
Oil	31.1	0.659	0.2049	9.07E-7	2.82E-7	0	0
Gas	36.7	0.432	0.1585	6.803E-6	2.497E-6	2.857E-5	1.048E-5
Geothermal	1.7	0.122	0.0021	0	0	0	0
Wind, Hydro, Solar & Nuclear	18.6	0	0	0	0	0	0
Combustible Renewables (Wood waste)	0.3	0	0	6.349E-5	1.905E-7	2.494E-4	7.482E-7
Municipal waste	0.3	0	0	9.07E-6	2.721E-8	2.494E-4	7.482e-7
Other fuels and waste	0.4	1.699	0.0068	9.07E-6	3.628E-8	2.494E-4	9.976E-7
TOTAL	100	--	**0.470**	--	**5.02E-06**	--	**2.99E-5**

The resulting average "grid" emission factors for Italy are:

CO_2 = 0.470 tonnes/MW-hr × 12/44 = 0.1282 tonnes C/MW-hr

CH_4 = 5.02E-06 tonnes/MW-hr
N_2O = 2.99E-05 tonnes/MW-hr

Using the same approach, results for the other countries are shown in Table F-5.

Table F-5. Average National "Grid" Emission Factors for 2000

Electricity Generation Approach

		Tonnes/MW-hr		
Country	**CO_2**	**C**	**CH_4**	**N_2O**
Australia	0.751	0.2045	1.54E-05	1.24E-04
Italy/Sicily	0.470	0.128	5.02E-06	2.99E-05
New Zealand	0.161	0.044	3.19E-06	1.84E-05
Philippines	0.494	0.135	6.86E-06	5.67E-05
Spain	0.428	0.117	7.75E-06	6.11E-05
UK	0.475	0.130	9.27E-06	6.52E-05
US	0.559	0.152	1.14E-05	8.95E-05

Including US data in this analysis provides a means of checking the results against GHG inventory information reported by the U.S. Energy Information Administration (EIA). For 2000, EIA reports 616.6 million metric tonnes of carbon emissions from fuel use used for electricity generation (EIA, 2002). This equates to $2{,}261\times10^6$ tonnes CO_2. Combining the U.S. CO_2 emission from Table F-5 (0.559 tonnes/MW-hr) with the total U.S. electric production from Table F-1 (4,030.3 TW-hr) results in $2{,}252\times10^6$ tonnes CO_2, a difference of about 0.4% from the EIA value.

Generation Factors Converted to Heat Input Basis

One approach to developing electric-grid emission factors on a heat input basis is to convert the emission factors in Table F-2 from a MW-hr output basis to a heat input basis by apply a fuel heating value. Fuel specific heating values for each of the countries are shown in Table F-1. These values can be combined into a single heating value for the country using a weighted average of energy production by fuel type from Table F-3, as shown by the Equation 5:

$$\text{National Heat Rate (BTU/kW - hr)} = \sum \frac{\text{TW - hr for Fuel Type}_i}{\text{TW - hr Total}} \times \text{Base Heat Rate for Fuel}_i \left(\frac{\text{BTU}}{\text{kW - hr}}\right) \qquad \text{(Equation 5)}$$

For the fraction of electricity generated from hard coal, heat values for hard coal and coal gases were averaged together. Similarly, for the fraction of electricity generated from combustible renewables, heat values for solid biomass and biogas were averaged. Electricity generated by wind, hydro, solar or nuclear does not have a corresponding heat input value. Geothermal electricity was converted to a heat input basis using an average heat rate for a geothermal steam turbine of 19,162 BTU/kW-hr from the Energy Inventory Improvement Program (EIIP, Volume VIII, Table 1.5-2, 1999).

The units conversion associated with combining the national heat rate values and the emission factors from Table F-2 is shown in Equations 6 and 7:

$$\frac{\text{tonne CO}_2}{\text{MW - hr}} \times \frac{\text{kW - hr}}{\text{BTU}} \times \frac{\text{MW} - \text{hr}}{1000\ \text{kW - hr}} \times \frac{9.486\times10^{-4}\ \text{BTU}}{\text{J}} \times \frac{10^{12}\ \text{J}}{\text{TJ}} = \frac{\text{tonne CO}_2}{\text{TJ}} \qquad \text{(Equation 6)}$$

$$\frac{\text{tonne CH}_4 \text{or N}_2\text{O}}{\text{MW - hr}} \times \frac{\text{kW - hr}}{\text{BTU}} \times \frac{\text{MW} - \text{hr}}{1000\ \text{kW - hr}} \times \frac{10^6\ \text{g}}{\text{tonne}} \times \frac{9.486\times10^{-4}\ \text{BTU}}{\text{J}} \times \frac{10^9\ \text{J}}{\text{GJ}} = \frac{\text{g CH}_4\ \text{or N}_2\text{O}}{\text{GJ}} \qquad \text{(Equation 7)}$$

An example calculation is provided for Italy.

Electricity Emission Factor Development for Italy – Generation Factors Converted to Heat Input Basis

CALCULATION METHODOLOGY:
The percent electric generation for each fuel, from Table F-3 is multiplied by the fuel specific heating values shown in Table F-1.

	A **% Generation**	**B** **BTU/kW-hr**	**A×B**
Hard coal	10.9	10,472	1,104
Brown coal	0.1	7,470	8
Oil	31.1	9,233	2,867
Gas	36.7	8,132	2,981
Geothermal	1.7	19,162	326
Wind, Hydro, Solar & Nuclear	18.6	NA	NA
Combustible Renewables (Wood waste)	0.3	8,114	23
Municipal waste	0.3	8,964	26
Other fuels and waste	0.4	9,338	38
TOTAL			**7,409 BTU/kW-hr**

Using Equations 6 and 7, the resulting heat rate is multiplied by the emission factors for Italy shown in Table F-5.

CO_2:

$$\frac{0.470\ \text{tonne}\ CO_2}{\text{MW-hr}} \times \frac{\text{kW-hr}}{7{,}409\ \text{BTU}} \times \frac{\text{MW}-\text{hr}}{1000\ \text{kW-hr}} \times \frac{9.486\times10^{-4}\ \text{BTU}}{\text{J}} \times \frac{10^{12}\ \text{J}}{\text{TJ}}$$

$$= \frac{60.22\ \text{tonne}\ CO_2}{\text{TJ}} \times \frac{12\ \text{tonne C}}{44\ \text{tonne}\ CO_2} = 16.42\ \text{tonnes C/TJ}$$

CH_4:

$$\frac{5.02\text{E-06 tonne}\ CH_4}{\text{MW-hr}} \times \frac{\text{kW-hr}}{7{,}409\ \text{BTU}} \times \frac{\text{MW}-\text{hr}}{1000\ \text{kW-hr}} \times \frac{10^6\ \text{g}}{\text{tonne}} \times \frac{9.486\times10^{-4}\ \text{BTU}}{\text{J}} \times \frac{10^9\ \text{J}}{\text{GJ}}$$

$$= 0.643 \frac{\text{g}\ CH_4}{\text{GJ}}$$

N_2O:

$$\frac{2.99\text{E-05 tonne}\ N_2O}{\text{MW-hr}} \times \frac{\text{kW-hr}}{7{,}409\ \text{BTU}} \times \frac{\text{MW}-\text{hr}}{1000\ \text{kW-hr}} \times \frac{10^6\ \text{g}}{\text{tonne}} \times \frac{9.486\times10^{-4}\ \text{BTU}}{\text{J}} \times \frac{10^9\ \text{J}}{\text{GJ}}$$

$$= 3.83 \frac{\text{g}\ N_2O}{\text{GJ}}$$

The weighted average heat rates and resulting emission factors are shown in Table F-6.

Table F-6. Average Country Heat Rates and "Grid" Emission Factors for 2000

Generation Derived Heat Input Values

		Emission Factors			
	Heat Rate,	CO_2	C	CH_4	N_2O
Country	**BTU/kW-hr**	**Tonnes/TJ**	**Tonnes/TJ**	**g/GJ**	**g/GJ**
Australia	8,901	80.07	21.84	1.637	13.26
Italy/Sicily	7,409	60.22	16.42	0.643	3.832
New Zealand	4,186	36.49	9.952	0.723	4.174
Philippines	10,631	44.05	12.01	0.612	5.061
Spain	4,953	81.93	22.34	1.484	11.68
UK	6,154	73.24	19.97	1.429	10.05
US	7,598	69.78	19.03	1.420	11.17

Emission estimates using this approach compare favorably to emission estimates using the factors from Table F-5. This is expected since both emission factor sets are derived from the same root emission factors (Table F-2). The minor differences that do occur, all less than 3.3%, result from combining heating values for a few fuel sources.

Heat Input Based Emission Factors

For this approach, heat-input based emission factors, such as those presented in Tables 2-2 through 2-4, can be assigned to the different fuel types used to generate electricity. The root emission factors are shown in Table F-7.

Table F-7. Energy Input Emission Factors

	CO2		CH4		N2O		
Fuel/Generation Type	**lb/ MMBTU**	**tonnes/TJ**	**lb/ MMBTU**	**g/GJ**	**lb/ MMBTU**	**g/GJ**	**Data Source**
Natural Gas Turbine	110	47.322	0.0086	3.700	0.003	1.291	AP-42 Table 3.1-2a
Oil Turbine	157	67.542	0.001867	0.803	0.00073	0.316	AP-42 Table 3.1-2a, 1.3-3, 1.3-8
PC-fired - Hard Coal	216.4	93.092	0.00154	0.662	0.002115	0.910	AP-42 Table 1.1-19 Average of bituminous and anthracite
PC-fired - Brown Coal	214.08	92.100	0.00154	0.662	0.002115	0.910	AP-42 Table 1.1-19 Average of sub-bituminous and lignite
Wood Waste Biomass	195	0[a]	0.004	1.678	0.013	5.594	AP-42 Table 1.6-3
Municipal Solid Waste Boiler	218.9	0[a]	Non-detect	0	Not available	0	AP-42 Table 2.1-3

[a] These bio fuels are considered carbon neutral, therefore the CO_2 emission factor converted to metric units has been set to zero.

The geothermal emission factor from the International Geothermal Association is converted to a heat input basis using the average geothermal steam turbine heat rate from the Energy Information Improvement Program, as shown:

$$\frac{0.122\ \text{tonne}\ CO_2}{\text{MW - hr}} \times \frac{\text{MW} - \text{hr}}{1000\ \text{kW - hr}} \times \frac{\text{kW - hr}}{19{,}162\ \text{BTU}} \times \frac{9.486 \times 10^{-4}\ \text{BTU}}{\text{J}} \times \frac{10^{12}\ \text{J}}{\text{TJ}}$$

$$= \frac{6.04\ \text{tonne}\ CO_2}{\text{TJ}} \times \frac{12\ \text{tonne C}}{44\ \text{tonne}\ CO_2} = 1.647\ \text{tonnes C/TJ}$$

Weighted average emission factors are calculated for each country by combining the emission factors from Table F-7 with the energy input values by fuel type from Table F-1. This weighted average approach is represented by Equation 8:

National Electric EF =

$$\sum \frac{\text{PJ for Fuel Type}_i}{\text{PJ Total}} \times \text{Base Energy Input EF by Fuel/Generation Type}_i \left(\frac{\text{tonnes}}{\text{TJ}} \text{ or } \frac{\text{g}}{\text{GJ}} \right)$$

where, EF = emission factor. (Equation 8)

Calculations for the heat input based emission factors for Italy are shown below.

Electricity Emission Factor Development for Italy – Heat Input Approach

CALCULATION METHODOLOGY:
Energy input values by fuel type are provided in Table F-1. These are divided by the total heat input associated with electricity generation in Italy to calculate the percent contribution of each fuel. The weighted emission factors are calculated by multiplying the percent contribution by the base EF from Table F-7.

Fuel/ Generation Type	% Contribution to Gross Energy Input	Tonnes/TJ		g/GJ		g/GJ	
		Base CO_2 EF	**Weighted CO_2 EF**	**Base CH_4 EF**	**Weighted CH_4 EF**	**Base N_2O EF**	**Weighted N_2O EF**
Hard coal + coal gases	14.69	93.092	13.675	0.662	0.0972	0.910	0.1337
Brown coal	0.103	92.100	0.0951	0.662	0.0006	0.910	0.0009
Oil	39.18	67.542	26.463	0.803	0.3146	0.316	0.1238
Gas	40.73	47.322	19.274	3.7	1.507	1.291	0.5258
Geothermal	4.45	6.04	0.2688	0	0	0	0
Wind, Hydro, Solar & Nuclear	NA	NA	NA	NA	NA	NA	NA
Combustible Renewables (Wood waste)	0.34	0	0	1.678	0.0057	5.594	0.0190
Industrial waste	0.15	94.172	0.1413	0	0	0	0
Municipal waste	0.35	0	0	0	0	0	0
TOTAL	100	--	**59.919**	--	**1.926**	--	**0.803**

The resulting average “grid” emission factors for Italy are:

CO_2 = 59.919 tonnes CO_2/TJ $\times$ 12/44 = 16.342 tonnes C/TJ

CH_4 = 1.926 g/GJ
N_2O = 0.803 g/GJ

Using the same approach, results for the other countries are shown in Table F-8.

Table F-8. Average National “Grid” Emission Factors for 2000

Heat Input Approach

	Tonnes/TJ		g/GJ	g/GJ
Country	**CO_2**	**C**	**CH_4**	**N_2O**
Australia	85.683	23.368	1.002	1.047
Italy/Sicily	59.919	16.342	1.926	0.803
New Zealand	34.443	9.393	2.205	1.043
Philippines	47.955	13.079	0.385	0.377
Spain	80.523	21.961	1.028	0.976
UK	69.517	18.959	2.058	1.151
US	75.693	20.644	1.366	1.191

To test the consistency between the electric generation based emission factors and heat input based emission factors, CO_2 emissions were calculated using the two approaches. Table F-9 presents the results.

Table F-9. Emission Factor Comparison

	Tonnes CO2		
Country	**Heat Input Basis**	**MW-hr Output Basis**	**% Difference**
Australia	173,069,288	156,573,605	10.54%
Italy/Sicily	127,870,531	130,088,429	-1.70%
New Zealand	5,943,088	6,278,788	-5.35%
Philippines	24,346,568	22,363,586	8.87%
Spain	94,318,174	96,295,596	-2.05%
UK	172,285,704	178,138,413	-3.29%
US	2,475,410,304	2,252,480,579	9.90%

Considering the fact that the two methods are developed from different root emission factors, based on different assumptions, the results from the two methods compare reasonably well (within 10%). For the U.S., the heat input method differs from the CO_2 emissions reported by EIA ($2{,}261\times10^6$ tonnes) by approximately 9.5%. The electric generation method compares more favorably, differing by only 0.4% from the EIA value.